2016 to 2020 Revised Regulatory Proposal

6 January 2016

2016 to 2020 Revised Regulatory Proposal

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1. Executive Summary

We are pleased to present to the Australian Energy Regulator (AER) this Revised Regulatory Proposal (RRP) for our 2016 to 2020 regulatory period, which builds on our Regulatory Proposal that we submitted in April 2015.

The AER's Annual Benchmarking Report 2015 confirms that we are the lowest cost Distribution Network Service Providers (DNSP) in the National Electricity Market. This RRP sets out a prudent investment plan to uphold this position while maintaining our network and continuing to meet the needs and expectations of our community.

In preparing our RRP we have:

- Assessed the AER's Preliminary Decision that it issued in November 2015;
- Taken into account the input and feedback provided by our stakeholders on our Regulatory Proposal;
- Responded to changes in our regulatory obligations since we submitted our Regulatory Proposal, for example in relation to the Power of Choice reforms and Electricity Safety (Electric Line Clearance) Regulations 2015; and
- Had regard for the Limited Merits Review applications initiated by the NSW and ACT electricity DNSPs, the NSW gas distributor and the Public Interest Advocacy Centre (PIAC), to which we are an intervener. The Australian Competition Tribunal (Tribunal) will make its determination on these applications by March 2016, which will enable the AER to reflect the outcomes into its Final Decision for our 2016 to 2020 regulatory period.

Our revised proposal for Standard Control Services (SCS):

- Reduces our gross capex forecast from $1,195.3 million to $1,189.1 million. This forecast rejects the AER's substitute forecast of $405.4 million (adjusted for real cost escalation) for Repex and proposes a revised forecast of $563.6 million in order to meet our reliability targets and safety obligations;
- Reduces our opex forecast from $780.1 million to $769.0 million (excluding DMIA and debt raising costs) and presents further information to justify our revised step changes which are driven by our regulatory obligations;
- Updates our regulatory depreciation forecast based on the methodology applied by the AER in its recent Final Decision for SA Power Networks;
- Includes a rate of return of 8.70 per cent per annum. The increase from 7.38 per cent per annum in our Regulatory Proposal reflects current market rates, the immediate transition to a trailing average approach to determining the return on debt, consistent with the AER's Rate of Return Guidelines, and the use of the 'adjusted SL CAPM' approach to determining the return on equity;
- Proposes refinements to the AER's calculation of the efficiency carry over amount for 2011 to 2015 in accordance with the Efficiency Benefit Sharing Scheme (EBSS); and
- Accepts the AER's proposed Service Target Performance Incentive Scheme (STPIS) targets on the basis that the AER also retains its Preliminary Decision on our Augmentation capex, Value of Customer Reliability (VCR) and demand forecast.

Our revised proposal for Alternative Control Services (ACS):

- Revises our metering expenditure forecast to align with the Australian Energy Market Commission's (AEMC) final rule change for metering and meter competition commencement on 1 December 2017;
- Accepts the AER's Preliminary Decision on our prices for our Quoted Services and for our Fee-Based Services, except for new connections and temporary supplies; and
- Accepts the AER's Preliminary Decision on our forecast public lighting opex and proposes revised forecast capex consistent with outcomes that we agreed with VicRoads and Local Councils.

Our RRP would increase our SCS prices by 15.2 per cent per annum from 2017 to 2019. This is driven by the revised rate of return and a true-up for the price cut of 8.72 per cent, which customers receive in 2016 as a result of the AER's Preliminary Decision. This price increase is largely offset by a price cut in ACS metering. We await the Tribunal's determination and the AER's Final Decision due in April 2016 to confirm the overall price impacts to our customers for the 2016 to 2020 regulatory period.

2. Proposal snapshot

We set out in Table 2-1 the key elements of our RRP, which we explain and justify in the remainder of this document.

Table 2-1: RRP snapshot

Standard control services ($M, Real 2015)	2016	2017	2018	2019	2020	Total
Capital expenditure forecast (gross)	253.8	261.2	237.5	223.5	213.2	1,189.1
Customer contributions	19.2	27.4	29.5	29.8	30.2	136.1
Regulatory asset base	2,189.9	2,309.9	2,390.9	2,448.9	2,492.1	n/a
Revenue requirements						
Return on capital (WACC 8.70%)	135.4	142.3	147.5	147.0	144.9	717.0
Regulatory depreciation (forecast) – Gross	118.9	121.1	133.4	141.4	145.0	659.9
Operating expenditure (including debt raising costs)	150.4	152.3	156.9	159.5	162.3	781.4
Efficiency benefit sharing scheme (carryover amounts)	2.7	17.6	6.5	9.5	0.0	36.3
Shared assets	2.1	(0.5)	(0.5)	(0.5)	(0.5)	(0.1)
Corporate tax allowance (Gamma 0.25)	31.7	31.7	34.5	37.3	38.0	173.3
Annual revenue requirement (unsmoothed)	441.2	464.5	478.3	494.2	489.6	2,367.7
X factor (%)	8.7%	(15.2%)	(15.2%)	(15.2%)	0.0%	n/a
Forecast energy consumption (GWh)	7,585.3	7,600.2	7,672.6	7,726.1	7,776.5	38,360.8
Alternative Control Services	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Metering annual revenue requirement (unsmoothed) ($M, Real 2015)	52.7	51.5	50.3	40.4	38.5	233.3
Metering X factor (%)	41.9%	29.6%	0.0%	0.0%	0.5%	n/a

Service classification and control mechanisms	Service classification	Control Mechanism
Standard control services – network and connection services	Accept AER classification	Accept revenue cap
Alternative Control Services – Types 5, 6 and smart meters – not subject to competition		Accept revenue cap
Alternative Control Services – OMR&R shared public lighting		Accept fee based
Alternative Control Services – ancillary network services and other connection services		Accept fee based
Negotiated services – other public lighting		Accept negotiating framework, subject to retaining our proposed dispute resolution arrangements
Unclassified		Accept – not applicable

Incentive schemes	
Efficiency benefit sharing scheme	Accept the AER's Version 2 of the scheme published in November 2013 but propose alternative EBSS carryover amount of $36 million for 2011 to 2015.
Service target performance incentive scheme	(a) If the AER retains its Preliminary Decision on our Augmentation capex, VCR and demand forecast then we accept the AER applying 5 per cent per annum revenue at risk and targets based on historical 5 year average, otherwise (b) We propose 1 per cent per annum revenue at risk and the relaxation of our targets.
Capital Efficiency Sharing Scheme	We accept the AER's Version 1 of the scheme.
Demand Management Incentive Scheme	(a) We accept Part A only of AER's Version 1 of the scheme published in April 2009 (b) We do not accept the AER's Preliminary Decision to allow DMIA of $0.4 million per annum, or $2.0 million over 2016 to 2020. We instead propose a total allowance of $6.6 million consistent with our Regulatory Proposal.
Victorian Government F-Factor Scheme	Accept application of F-Factor Scheme Order 2011 issued under the National Electricity (Victoria) Act 2005. Participate in the Victorian Government's public consultation process about the scheme.
Proposed additional pass-through events	
Accept alternative definitions in the AER's Preliminary Decision for the insurance cap event, the insurer's credit risk event and the natural disaster event. Accept the AER's decision not to have a NECF event. Propose amendments to the AER's drafting of the terrorism and retailer insolvency events.	

3. About our Revised Regulatory Proposal

This is our RRP to the AER for our regulatory period, 1 January 2016 to 31 December 2020.

We have developed this RRP following communication and engagement with our customers and other stakeholders. It details, in particular, the revenues that we require to maintain the quality, safety, reliability and security of our distribution services, and of our assets that we use to deliver them.

3.1. AER's Preliminary Decision

On 30 April 2015, we submitted a compliant Regulatory Proposal to the AER for our 2016 to 2020 regulatory period in accordance with the requirements of Chapter 6 of the National Electricity Rules (the NER) and the transitional arrangements in Chapter 11 of the NER.

Our Regulatory Proposal was subject to public consultation and a review by the AER and its consultants. On 29 October 2015, the AER published its Preliminary Decision for our Distribution Determination for the 2016 to 2020 regulatory period. The AER's Preliminary Decision identifies each of the constituent decisions it is required to make under the NER. It has been used to set our distribution prices for 2016.

Clause 11.60.4 of the NER requires that the AER, following further stakeholder consultation, must revoke its Preliminary Decision (which for all intents and purposes was a final decision for 2016) and substitute it with a new Distribution Determination to be published by 30 April 2016[1]. The final decision will incorporate a 'true-up' revenue adjustment to account for any difference in our allowed revenue between the Preliminary and Final Decisions. The AER's Final Decision will set prices for the remaining four years of the 2016 to 2020 regulatory period.

3.2. Our RRP

This document consists of our submissions on the revocation and substitution of the AER's Preliminary Decision and, for ease of reference, is referred to as our RRP.

This RRP is presented for consideration by the AER under paragraph 11.60.4(f) of the NER.

In submitting this RRP, we refer to and rely upon our Regulatory Proposal including all previous material provided to the AER as part of the Regulatory Proposal and determination process, including the material submitted in our answers to the AER's Information Requests (the **original material**), without re-submitting this material with this RRP.

When reviewing the AER's Preliminary Decision and in preparing this RRP, we have also considered and incorporated information that was not available when our Regulatory Proposal was submitted in April 2015.

The RRP comprises and incorporates:

- The Regulatory Proposal;
- The original material;
- Revisions to the Regulatory Proposal or original material set out in this document, including revised versions of:
  - Reset Regulatory Information Notice (RIN) templates;
  - Post-Tax Revenue Model (PTRM) and Roll Forward Model (RFM); and
  - Capex and Opex models.
- Submissions on the revocation and substitution of the AER's Preliminary Decision and further materials related to those submissions.

[1] We note that in the same way that the 29 October 2015 decision is not a Preliminary Decision, the 30 April 2016 decision is not a final decision. However, we propose to adopt this terminology for consistency and simplicity when referring to the Distribution Determination that will be made on 30 April 2016.

Insofar as there is an inconsistency between one or more of these component parts of the RRP, we intend for the revisions to the Regulatory Proposal or original material set out in this RRP to prevail and to be considered by the AER. In particular, revisions in this RRP to the Regulatory Proposal will prevail to the extent of any inconsistency.

4. Next steps and our stakeholders' feedback

Our customers and other stakeholders' views on our RRP are important to us. We welcome feedback through any of the following channels:

Channel	Details
Email	youreenergy@ue.com.au
Post	EDPR Feedback PO Box 449 Mount Waverley VIC 3149
Phone	1300 131 689
Online	unitedenergy.engagementhq.com

The AER has indicated that it will invite submissions on our RRP up until 4 February 2016. We will continue to engage with our stakeholders up until (and after) this period, including to explain what we have proposed.

The AER indicated in its Preliminary Decision that it will issue its final Distribution Determination by the end April 2016.

We have set our prices for our distribution services for the 2016 calendar year based on the AER's Preliminary Decision. We will deal with any differences between the AER's Preliminary and final Distribution Determinations that affect our allowed revenues for 2016 through a revenue 'true-up' from 1 January 2017.

5. Capex forecasts

Key messages:

- We accept the AER's labour and material escalations and have reapplied these in our revised capex forecast.
- We accept the AER's revised forecast for Augmentation capex of $127.0 million (adjusted for escalations to $124.3 million).
- We have increased our Gross Customer Connections capex from $249.1 million to $316.8 million due to increased volumes, project costs and Horizon Projects. Two thirds of this $67.7 million increase will be recovered through up-front customer contributions.
- We do not accept the AER's revised forecast for Replacement capex of $413.9 million. Our revised Repex forecast is $563.6 million, which we consider is necessary to address our deteriorating reliability and safety performance.
- We accept the revised forecast for Non-network Other capex of $30.9 million.
- We accept the AER's base Non-Network IT capex forecast of $103.6 million but consider that additional capex is required for Power of Choice and RIN reporting. We have proposed revised amounts for these projects based on more up-to-date information. Our revised Non-Network IT capex forecast is $153.4 million.

5.1. AER's Preliminary Decision

In its Preliminary Decision, the AER rejected our proposed capex forecast (net of customer contributions) for 2016 to 2020 of $1,104.0 million. The AER substituted our proposal with its own forecast of $814.8 million. This represented a reduction of $289.2 million or 26 per cent. The AER's reduction relates to four areas, as illustrated in Table 5-1.

Table 5-1: AER's capex reductions 2016 to 2020 ($M, Real 2015)

	Regulatory Proposal	AER Preliminary Decision	AER Reduction	% Reduction
SYSTEM ASSETS				
Augmentation	166.5	127.0	(39.5)	(24%)
Connections	249.1	249.1	0.0	0%
Replacement	585.1	413.9	(171.2)	(29%)
Sub-total system assets	**1,000.7**	**790.0**	**(210.7)**	(21%)
NON-NETWORK ASSETS				
Non-Network General Assets – ICT	163.7	103.6	(60.1)	(37%)
Non-Network General Assets – Other	30.9	30.9	0.0	0%
Sub-total non-network assets	**194.6**	**134.5**	**(60.1)**	(31%)
Escalation adjustment		(18.4)	(18.4)*	
Total capex	**1,195.3**	**906.1**	**(289.2)**	(24%)

	Regulatory Proposal	AER Preliminary Decision	AER Reduction	% Reduction
Less customer contributions	91.3	91.3	0.0	0%
Net capex	**1,104.0**	**814.8**	**(289.2)**	(26%)

* For the purposes of this RRP, we have allocated this $18.4 million real cost escalation adjustment between our capex categories as follows: Augex $2.6 million; Connections $7.3 million; and Repex $8.5 million.

5.2. Revised capex forecast overview

This chapter details how we have revised our capex forecasts for each year of our 2016 to 2020 regulatory period. Table 5-2 overviews our revised capex forecast and details the percentage change we are proposing from the AER's Preliminary Decision.

Table 5-2: Revised forecast capex 2016-20 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total	% change from AER's PD
SYSTEM ASSETS							
Augmentations	33.8	30.7	29.5	19.3	11.0	124.3	(2.1%)
Connections	61.7	63.2	63.2	63.9	64.8	316.8	27.2%
Replacement	113.3	114.4	119.1	113.6	103.2	563.6	36.2%
Sub-total system assets	**208.9**	**208.3**	**211.7**	**196.8**	**179.0**	**1,004.7**	27.2%
NON-NETWORK ASSETS							
Non-Network General Assets – ICT	30.9	48.9	22.2	22.4	29.1	153.4	47.8%
Non-Network General Assets – Other	14.0	4.0	3.5	4.3	5.1	30.9	0.0%
Sub-total non-network assets	**44.9**	**52.9**	**25.7**	**26.7**	**34.2**	**184.3**	**36.8%**
Total capex	**253.8**	**261.2**	**237.5**	**223.5**	**213.2**	**1,189.1**	**31.2%**
Less customer contributions	19.2	27.4	29.5	29.8	30.2	136.1	48.9%
Net capex	**234.6**	**233.8**	**207.9**	**193.7**	**183.0**	**1,053.0**	**29.2%**

In preparing our revised capex forecast we have accepted both the AER's real material cost escalator of zero and its real labour cost escalator, being an average of DAE and BIS's escalators. Therefore, even when we have otherwise maintained our forecasts from our Regulatory Proposal or accepted the AER's Preliminary Decision forecasts, there will be some changes in the forecast which reflect our adoption of the AER's escalators.

5.3. Augmentation capex

We accept the AER's forecast in its Preliminary Decision for our Augmentation capex of $127.0 million for 2016 to 2020. When adjusted for escalations this amounts to $124.3 million.

Table 5-3: Augmentation capex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	34.7	32.3	37.8	36.9	24.9	166.6
AER Preliminary Decision *	34.7	32.3	30.9	18.7	10.4	127.0
RRP	33.8	30.7	29.5	19.3	11.0	124.3

* AER Preliminary Decision does not include its adjustment for real cost escalation

5.4. Connections capex and customer contributions

In its Preliminary Decision, the AER accepted our gross connections capex forecast (including customer contributions) for 2016 to 2020 of $249.1 million.

We have reviewed the forecast volumes and project costs that we used in preparing our gross connection capex forecast. As a result, while retaining our original forecasting methodology, we are now proposing an increase in our gross connections forecast of $249.1 million for 2016 to 2020 to $316.8 million. This is shown in Table 5-4 below.

Table 5-4: Gross connections capex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	48.2	49.3	50.6	50.1	50.9	249.1
AER Preliminary Decision *	48.2	49.3	50.6	50.1	50.9	249.1
RRP	61.7	63.2	63.2	63.9	64.8	316.8

* AER Preliminary Decision does not include its adjustment for real cost escalation

We are also proposing an increase in our original customer contributions forecast of $91.3 million for 2016 to 2020 to $136.1 million. This is shown in Table 5-5 below. This means that $44.8 million of the total increase of $67.7 million is recovered through up-front customer contributions from developers, rather than through DUOS charges levied on all customers.

Table 5-5: Customer contributions ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	17.7	18.1	18.3	18.7	18.5	91.3
AER Preliminary Decision	17.7	18.1	18.3	18.7	18.5	91.3
RRP	19.2	27.4	29.5	29.8	30.2	136.1

Table 5-6 details the drivers of the changes to our gross connections capex forecast between our Regulatory Proposal and our RRP. These changes are explained further below.

Table 5-6: Drivers of revised forecast ($M, Real 2015)

Driver	Increase / Decrease	% Increase / (Decrease)	Cumulative Increase / (Decrease)	Cumulative CIC Capex
Initial Submission				249.1
Update Volumes	17.6	7.0%	7.0%	266.7
Update Project Costs	48.2	19.3%	26.4%	314.8
Horizon Projects	2.0	0.8%	27.2%	316.8
Total			**27.2%**	**316.8**

5.4.1. How we prepare our gross connections capex and customer contribution forecasts

We described in our "Capital Expenditure Overview – Connections" document that we submitted with our Regulatory Proposal the methodology that we use to prepare our gross connections capex and customer contribution forecasts. In summary, our approach involves:

- Forecasting our gross connections capex for non-unitised and unitised connections at our three-letter Activity Code[2] level:
  - For non-unitised projects we prepare our forecasts based on the following components: project costs (updated for forecast overheads); volumes, Australian Construction Industry Forum (ACIF) growth indices; expenditure profile; expenditure forecasts of large existing projects (Horizon Projects); initiation profile; and real cost escalations. We apply combinations of these components to forecast existing and future non-unitised projects; and
  - Unitised projects – we prepare our forecasts based on the following components: volumes; ACIF growth indices; standardised unit rates contractually agreed with our Service Providers (ZNX and Downer); and real cost escalations.
- Forecasting customer contribution revenues from both cash contributions and gifted assets; and
- Determining the split of gross connections capex and customer contributions by service classification (i.e. between SCS and ACS.

We have continued to apply this methodology in this RRP. We set out below the basis of our proposed revised forecasts.

5.4.2. Gross connections capex

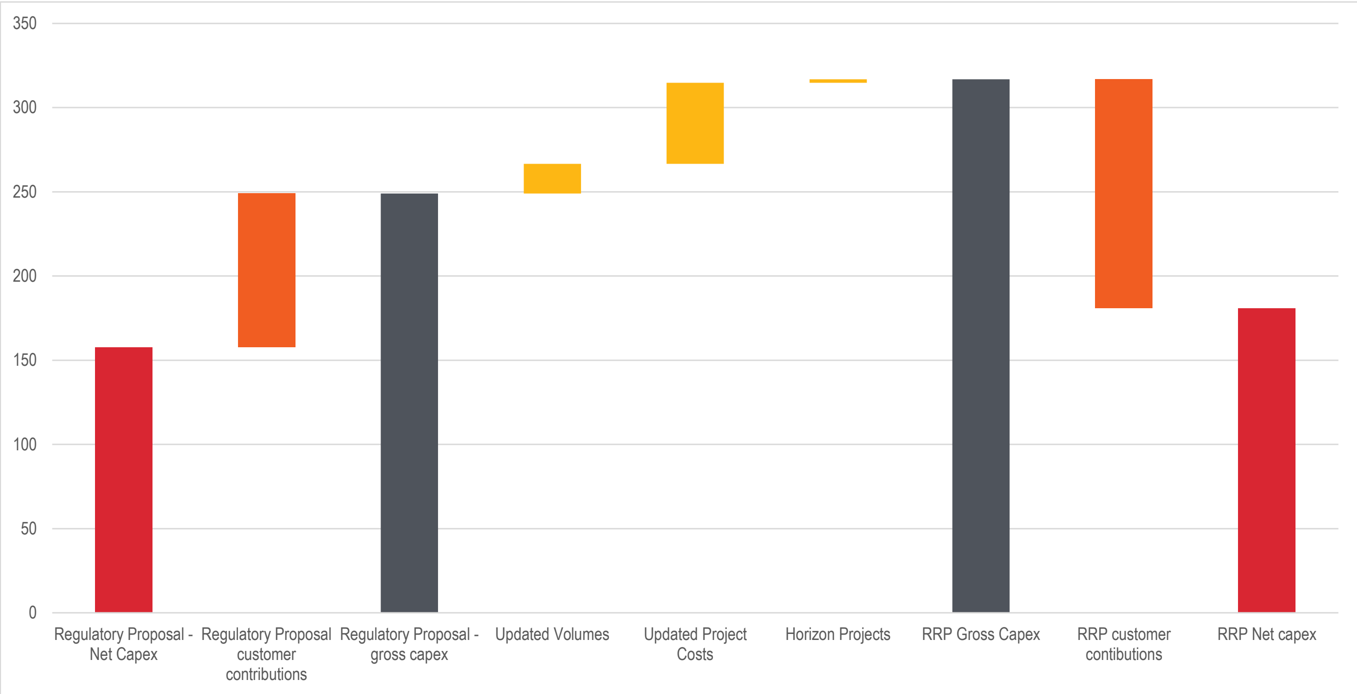
We have revised our gross connections capex forecast in this RRP for three factors:

- Updated volumes for non-unitised and unitised projects;
- Updated project costs for non-unitised projects and unit costs for unitised projects; and
- Updated forecasts of existing committed projects (Horizon Projects).

[2] A description of our two and three-letter Activity Codes is provided in Appendix A of our "Capital Expenditure Overview – Connections" document that was submitted with our Regulatory Proposal. This also provide a mapping of our Activity Codes to the AER's Service Classification.

The impact of these revisions are shown in Figure 5-1.

Figure 5-1: Gross connections capex forecast – drivers of forecast changes ($M, Real 2015)



Our proposed revisions are explained and justified below.

Table 5-7 details our revised gross connections capex forecast by connection type (two-letter Activity Code), which is an aggregation of the forecasts that we prepare at the more detailed three-letter Activity Code level.

Table 5-7: Gross connections capex forecast by Connection Type (two-letter code) ($M, Real 2015)

Connection Type	Capex activity description	Regulatory Proposal 2016-20	RRP 2016-20	Difference
Business Supply (CB)	Includes new/upgrade LV works, LV alteration and extension for temporary supply for construction activities, upstream HV works (new/upgraded feeders) and new/upgrade works for substations (ground, kiosk, indoor & pole top).	141.8	173.6	31.8
Urban residential supply (CH)	Includes new/upgrade substations, HV works and new OH/UG LV reticulation network.	32.2	31.6	(0.5)
Recoverable works (CR)	HV/LV OH lines relocation, asset undergrounding and asset relocations for road authorities, rail crossing projects and building developers.	35.6	53.1	17.5
Rural Supply (CS)	Includes HV OH/UG line extension for new rural residential/commercial developments	5.4	6.1	0.7
Multi-occupancy supply (CD)	Includes new LV underground lines (LV Pit to LV Pole)	34.1	52.4	18.3
Total		**249.1**	**316.8**	**67.7**

Updated volumes for non-unitised and unitised projects

We forecast our volumes for both non-unitised projects and unitised projects by Activity Code based on the number of projects initiated each year. Our methodology involves taking the number of projects in the latest year for each Activity Code and applying the ACIF growth indices to forecast the number of projects for each Activity Code over the next period.

In our Regulatory Proposal, we used 2014 actual volumes as the baseline for preparing our forecasts.

Since submitting our proposal, we now have 2015 actual volumes. Table 5-14 details the change in our actual volumes between 2014 and 2015 by connection type (two-letter Activity Code). It shows that there:

- Have been significant increases in volumes for Business Supply projects (CB) and particularly multi-occupancy projects (CD);
- Has been a significant decrease in volumes for recoverable works (CR); and
- Have been small increases in volumes for urban residential supply (CH) and rural supply (CS).

Table 5-8: Change in actual connection volumes by Activity Code between 2014 and 2015

Two-letter Activity Code	2014 Actual	2015 Actual
Business supply (CB)	447	539
Urban residential supply (CH)	123	128
Recoverable works (CR)	308	244
Rural supply (CS)	34	35
Multi-occupancy supply (CD)	2,807	4,836

The increase in Business supply (CB) actual volume is due to a recent increase in mixed developments (residential/commercial) and an increase in business park developments. The increase in multi occupancy (CD) actual volume is due to recent increases in small residential developments for additions and alterations. The ACIF forecast demonstrates that these increases are likely to be sustained for 2015-2020.

We consider that it is more appropriate to use our 2015 actual volumes to forecast our gross connections capex than our 2014 actual volumes because they are more recent and therefore more likely to be representative of our future requirements.

We have therefore re-applied the 2015 actual volumes in our gross connections capex model, while holding the other components of the forecast constant.

Table 5-9 details the impact on our gross connection capex forecast of using our actual 2015 volumes compared with our 2014 volumes that we used in our Regulatory Proposal forecast.

Table 5-9: Impact of change in actual connection volumes by Connection Type between 2014 and 2015 ($M, Real 2015)

	Regulatory Proposal	RRP based on updated Volumes	Variation
Business supply (CB)	141.8	155.1	13.4
Urban residential supply (CH)	32.2	32.0	(0.1)
Recoverable works (CR)	35.6	19.2	(16.4)
Rural supply (CS)	5.5	5.5	0.0
Multi-occupancy supply (CD)	34.1	54.7	20.6
Total	**249.1**	**266.6**	**17.6**

Updated project costs for non-unitised projects and unit costs for unitised connections

We determine the project costs for our non-unitised projects by:

- Sourcing from our SAP system our detailed monthly capex for the last three financial years for our existing projects;
- Identifying by Activity Code the existing projects in the latest year with “closed” status;
- Excluding existing Horizon Projects[3] from project cost calculations; and
- Determining the average cost per project by three-letter Activity Code for the existing projects in the latest year. This is calculated as the sum of the total costs of the existing projects in the latest year (over the last three years) divided by the number of projects in that year.

In our Regulatory Proposal we used actual 2014 project costs to prepare our forecasts.

Since submitting our Regulatory Proposal, we now have actual 2015 project costs. Table 5-10 details the change in our actual project costs between 2014 and 2015 by connection type.

Table 5-10: Change in Project Costs by Activity Code between 2014 and 2015 ($, Real 2015)

Two-letter Activity Code	2014 Project Costs - $ per project	2015 Project Costs - $ per project
Business supply (CB)	51,864	58,736
Urban residential supply (CH)	70,882	81,040
Recoverable works (CR)	35,642	72,423
Rural supply (CS)	32,313	28,164
Multi-occupancy supply (CD)	3,160	3,237

The key causes of step increases in project costs are:

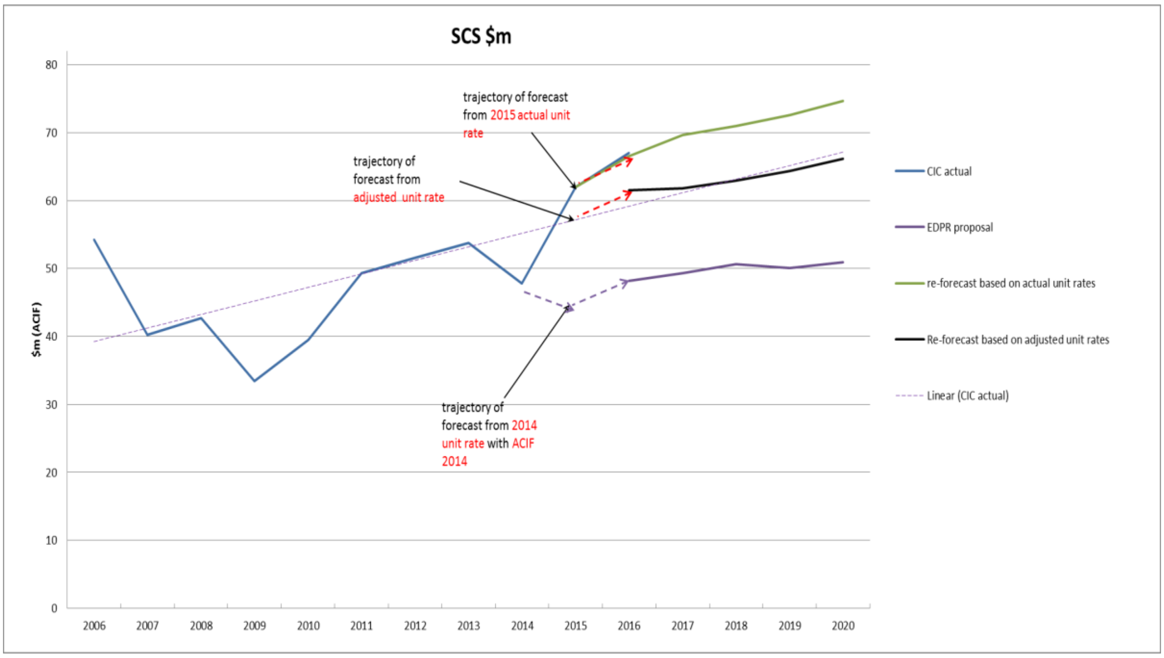
- From 2015, recoverable works (CR) include major asset relocation projects driven by major road developments, undergrounding of rail level crossings and building developments that require asset relocations and/or removal. Many of these projects are located in high density population areas, which have high customer requirements

[3] Very large customer projects that arise from time to time that often require major upstream augmentations.

such as safety clearances, long asset relocation detours and street vegetation. This considerably increases the cost of these projects. Over the next five years around $2 billion of rail crossing and roads development projects will need to be constructed, which will require us to undertake asset relocations, removals or undergrounding.[4] We therefore expect the increase in CR between 2014 and 2015 to continue in the 2016 to 2020 regulatory period;

- From 2015, business supply projects (CB), in particular HV projects, include the connection of large customers such as data centres, hospitals, railway supply and major building developments, which incur upstream connection works on our network. These types of projects involve installing dedicated assets and therefore require a higher customer contribution. Many of these projects are located in high density population areas, which have high customer requirements such as HV undergrounding and indoor installations, as well as backup network supply. This considerably increases the costs of these projects. We have identified $1 billion of building development projects that will require new business supply to be constructed in our supply area in the next five years[5]. We expect the step increase driven by the change in the style of project experienced from 2014 to 2015 to be sustained in the 2016 to 2020 regulatory period;
- The costs of many recoverable works projects (CR) completed in 2014 were capitalised in 2015. As the status of these projects was not reported as “Closed” in 2014, their cost were not identified for the 2014 project cost calculations. Instead, they were identified in the 2015 project cost calculations. Appendix B provides examples of projects that formed part of the 2015 project cost calculation rather than the 2014 project cost calculations. This resulted in relatively low project costs in 2014 and relatively high project costs in 2015. Rather than using either the low 2014 project costs or the high 2015 project costs, we have adjusted the project costs to align with the trend over the two years. This involved adjusting the forecast project costs to 88 per cent of the 2015 project costs, as illustrated in Table 5-2; and
- The costs of many business supply (CB) projects completed in 2014, including for indoor substations, new kiosk substations and pole substations, were capitalised into 2015 for the same reason as noted above for CR projects.

Figure 5-2: Connections capex forecast with capex linear trend ($M, Real 2015)



We have therefore applied the adjusted 2015 project costs to our gross connections capex model, holding our other components of the forecast constant.

[4] Refer to Cordell Major Projects List at Appendix A of this RRP, ACIF Forecast Dashboard, August 2015

[5] Refer to Cordell Major Projects List at Appendix A of this RRP, ACIF Forecast Dashboard, August 2015

Table 5-11: Impact of change in project costs for connections capex between 2014 and 2015 ($M, Real 2015)

	Regulatory Proposal	RRP based on updated project costs	Variation
Business supply (CB)	141.8	158.2	16.4
Urban residential supply (CH)	32.2	31.7	(0.4)
Recoverable works (CR)	35.6	69.5	33.9
Rural supply (CS)	5.5	6.1	0.6
Multi-occupancy supply (CD)	34.1	31.7	(2.4)
Total	**249.1**	**297.2**	**48.2**

Updated Horizon Projects and existing committed projects

There are three committed Horizon Projects that started in 2015. These projects relate to Business Supply (CB) projects. Part of this expenditure is expected to occur between 2016 and 2018 and amount to $2 million. These projects were not included in our Regulatory Proposal as they were not committed or confirmed at that stage by customers.

Conclusion

We propose an increase in our gross connections capex forecast (including customer contributions) for 2016 to 2020 from $249.1 million to $316.8 million. Of this 27.2 per cent increase, 7 per cent is due to volume increases, 19.3 per cent increase is due to project costs and 0.8 per cent is due to existing Horizon Projects. Two thirds of the $67.7 million increase will be recovered through up-front customer contributions from developers, rather than through DUOS charges levied on all customers.

The volume increase is driven by business supply and multi-occupancy projects sustained by extended periods of low interest rates and a high demand for housing.

The project cost increase is driven by a change in the style of projects, with more rail crossings, road works, and building developments in built-up areas being undertaken. Also high customer requirements and the connection of large customers with new dedicated assets, will increase customer contributions and hence project costs. As these projects cost significantly more than the average in their category, the higher proportion of these projects increases the project cost. The relevant programs of works forecast over 2016 to 2020 indicates the recent increases will continue for the 2016 to 2020 regulatory period.

5.4.3. Customer contribution forecasts

We forecast our customer contributions by connection type (two-letter Activity Code). We deduct our forecast customer contributions from our gross connections capex forecasts calculated above to determine our net connections capex forecasts.

Our customer contributions comprise cash contributions and gifted assets.

We have updated our forecast cash contributions using our Statement of Works (SoW) model that prices the upfront cash contributions required from customers. This forecast is consistent with both:

- The Essential Services Commission of Victoria (ESC) Guideline 14; and
- The AER's national Customer Contributions Guidelines.

Our cash contributions are forecast by:

- Backcasting the amount that customers would have paid on actual projects in the previous regulatory period based on an SoW model updated for:

- Marginal cost of reinforcement (MCR) to reflect current actual costs;
- An X factor of zero;
- Our 2016 tariffs; and
- Opex so that it is excluded from both incremental revenue and incremental cost.

- Using these back-cast cash contribution values to determine the historical average percentage of cash contributions that would have resulted from every dollar of gross connections capex by connection type (at a two-letter Activity Code);
- Applying these percentages to the connections capex to determine the cash contribution by connection type (at a two-letter Activity Code);
- Determining the profile for the timing of the recognition of the cash contributions revenue based on:
    - Charging customers the cash contribution up-front when the offer is accepted;
    - Holding the cash contribution in trust during the course of the project; and
    - Recognising the revenue when the project is completed.

  In this way we forecast when to recognise our cash contributions as revenue based on the historical timing of projects.

We forecast our customer contributions through gifted assets based on:

- The historic trend in our gifted assets in recent years; and
- Internal knowledge and understanding of potential projects that we expect will occur in coming years.

The sum of the annual cash contributions and gifted assets by two-letter activity code gives our annual customer contributions.

Table 5-12 details the change in our customer contributions forecast between our Regulatory Proposal and this RRP.

Table 5-12: Change in customer connections forecast ($M, Real 2015)

	Regulatory Proposal	RRP
Business supply (CB)	54.5	43.9
Urban residential supply (CH)	11.6	16.3
Recoverable works (CR)	22.4	40.9
Rural supply (CS)	3.0	3.3
Multi-occupancy supply (CD)	-	31.7
Total	**91.3**	**136.1**

5.5. Replacement capex (Repex)

5.5.1. Introduction

In its Preliminary Decision, the AER rejected our proposed Repex forecast for 2016 to 2020 of $585 million. The AER substituted our proposal with a forecast of $413.9 million – a reduction 29 per cent. Our revised Repex forecast is $563.6 million.

Table 5-13 compares our original and revised forecasts with the AER's Preliminary Decision.

Table 5-13: Replacement capex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	118.9	125.6	124.8	113.8	101.9	585.0
AER Preliminary Decision *	82.0	85.7	86.9	83.3	76.1	413.9
RRP	113.3	114.4	119.1	113.6	103.2	563.6

* AER Preliminary Decision does not include its adjustment for real cost escalation

The AER assessed our Repex forecast on the basis of four key categories being:

1. Modelled Repex – this relates to Repex that is assessed by the AER's Repex model;
2. Pole top structures and SCADA;
3. Other Unmodelled; and
4. Victorian Bushfire Royal Commission (VBRC).

In preparing its forecast, the AER reallocated some capex between the four categories – in particular, from Modelled and Other Unmodelled to VBRC. These modifications are shown in Table 5-14, below which reconciles the AER's Preliminary Decision with our forecast in our Regulatory Proposal.

Table 5-14: Forecast replacement capex 2016 – 2020 ($M, Real 2015)

Repex categories	Regulatory Proposal	AER Reallocation in Preliminary Decision		Adjusted Regulatory Proposal	AER Preliminary Decision *	AER percentage disallowed
1. Modelled Repex	296.5	Conductors to VBRC	4.9	271.2	220.3	18.8%
		HV ABC to VBRC	19.0			
		LV ABC to VBRC	1.3			
		Total to VBRC	**25.3**			
2. Pole Top Structures and SCADA	133.7	N/A		133.7	130.1	2.7%
3. Other – Unmodelled	109.6	Ampact to VBRC	4.8	104.8	28.0	73.3%
		Total to VBRC	**4.8**			
4. VBRC	45.3	Total to VBRC	30.1	75.4	35.5	52.9%
Total	**585.1**			**585.1**	**413.9**	**29.3%**

* AER Preliminary Decision does not include its adjustment for real cost escalation

We do not accept the AER's substitute Repex forecast of $413.9 million because it is insufficient to enable us to meet our STPIS targets and to satisfy our compliance obligations, including safety. As a consequence, the AER's substitute forecast will not satisfy the capex objectives in the NER.

We have reviewed our Repex forecast in light of the AER's Preliminary Decision and propose a forecast of $563.6 million for 2016 to 2020.

Table 5-15 breaks down our forecast for 2016 to 2020 into the four key categories and compares it to our actual Repex for the 2011 to 2015 regulatory period and to the AER's Preliminary Decision.

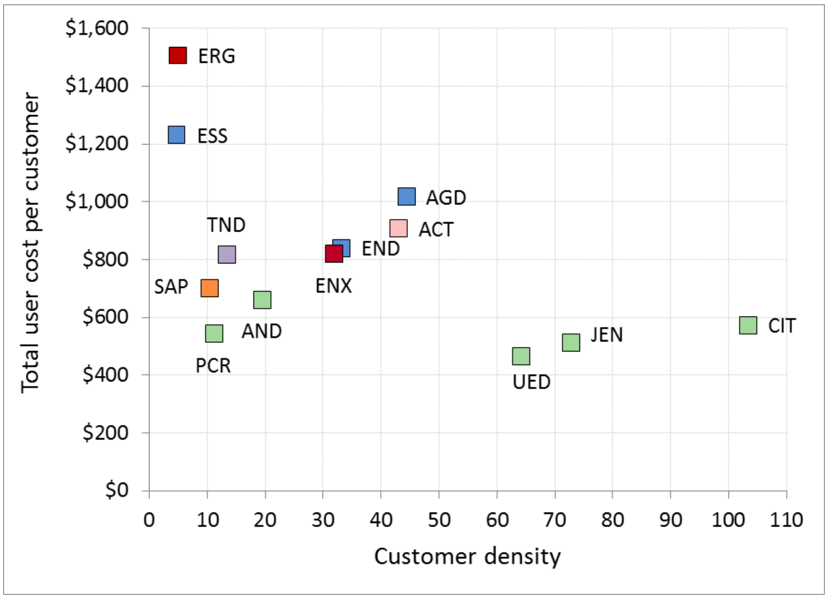
Table 5-15: Revised Repex forecast ($M, Real 2015)

	2011-15		2016-20	
	AER Allowance	Actual	Preliminary Decision *	RRP
1. Modelled Repex		234.8	220.3	266.8
2. Pole Top Structures and SCADA		132.3	130.1	131.4
3. Other – Unmodelled		45.5	28.0	112.2
4. VBRC		24.4	35.5	53.3
Total	**368.1**	**437.0**	**413.9**	**563.6**

* AER Preliminary Decision does not include its adjustment for real cost escalation

Table 5-15 shows that our actual Repex exceeded the AER's allowance by around 20 per cent. This is because we required additional expenditure, rather than because we were inefficient. Indeed, Figure 8 from the AER's 2015 Annual Benchmarking Report (replicated below) shows that we are the lowest cost DNSP in the NEM. This confirms that our costs are efficient and that overspend in the 2011 to 2015 regulatory period is therefore also efficient. It also indicates that the AER's allowance was too low for that period.

Figure 8: Total cost per customer against customer density (2010–14 average)[6]



[6] AER, Annual Benchmarking Report, Electricity distribution network service providers, November 2015, Figure 8, page 15.

Despite the substantial increase in actual Repex, our reliability performance has deteriorated. We have incurred STPIS penalties of approximately $40 million for our reliability performance over the period 2011 to 2014. The increase in actual Repex is driven by:

- Our ageing assets, whereby an increasing proportion of assets are entering their "wear out" phase;
- A deteriorating trend in our reliability performance;
- A deteriorating trend in our network safety performance; and
- Increased investment in response to the findings of the VBRC.

All of this underscores the extent to which the AER's allowance for 2011 to 2015 was insufficient and the need for an increase in our Repex allowance in the 2016 to 2020 regulatory period.

However, we are concerned that the AER's Preliminary Decision would perpetuate the results of its Final Determination for the 2011 to 2015 regulatory period. The AER appears to mistakenly consider that it has provided us with an increase in Repex for 2016 to 2020 compared to our actual Repex in 2011 to 2015, whereas Table 5-15 clearly shows that this is not the case. The AER states in its Preliminary Decision that[7]:

> *Having considered its proposal, we accept that United Energy requires increased Repex over 2016–20—compared to 2011–15—to manage deterioration in asset condition because a greater proportion of its assets are reaching the end of their economic life.*

In making this statement, the AER recognises the deterioration in asset condition and the increasing proportion of assets that are reaching the end of their economic lives. The AER's commentary is consistent with our Regulatory Proposal, which highlighted the increasing risk to reliability as a result of the increasing proportion of assets approaching end of life.

Despite this, Table 5-15 shows that the AER has in fact reduced our 2016 to 2020 Repex to 6 per cent below our 2011 to 2015 actual Repex, from $437.0 million to $413.9 million.

It is unsustainable for our Repex in the 2016 to 2020 regulatory period to be lower than our historical Repex, as it will not allow us to maintain our reliability and safety outcomes in accordance with the capex objectives in the NER. It appears from the commentary in the Preliminary Decision that the AER accepts this point, but it has not reflected this into our Repex allowance.

We have revisited each of the four Repex categories in light of the AER's Preliminary Decision and have addressed the concerns raised by the AER and its consultant. Table 5-16 summarises our response to the matters that the AER raised in its Preliminary Decision, including the key actions and positions that we have reflected in our RRP.

Table 5-16: Key actions and positions for our 2016 – 2020 revised Repex forecast ($M, Real 2015)

	Summary of our Response to the AER's Preliminary Decision - key actions and positions
Modelled Repex	We do not accept the AER's Preliminary Decision. Nuttall Consulting has updated its review of the AER's application of the Repex model. This supports the view that it is valid to rely on our forecast unit costs and that the AER should not substitute our forecast with an alternative based on historical unit rates. Our forecast unit costs are consistent with the proposed work volumes and mix and are based on competitively tendered contracts, which the AER has previously reviewed and considered to be efficient. Section 5.5.5 below provides further information about our Modelled Repex and references the Nuttall Consulting Report and other supporting documentation.
Pole Top Structures and SCADA	The AER accepted our Repex forecasts for Pole Top Structures and SCADA, except for our forecast cost escalation. We accept the AER's Preliminary Decision on Pole Top Structures and SCADA. Section 5.5.6 below provides further information.
Other – Unmodelled	We do not accept the AER's Preliminary Decision on Unmodelled Repex. The AER concluded that "it is not clear why the need to replace these assets has suddenly and significantly arisen in the forthcoming period".

[7] AER, United Energy distribution determination 2016 to 2020, Overview, page 21.

	Summary of our Response to the AER's Preliminary Decision - key actions and positions
	To assist the AER assess our forecast, we have: – Clarified that this expenditure is not concerned with replacing assets but is for additional expenditure to maintain reliability, safety, power quality and environmental outcomes. While other DNSPs have classified this type of expenditure as Augex (not related to demand) we have maintained our categorisation of this as Other Repex because it involves maintaining the network and therefore should properly be classified as Repex; – Corrected our historical data in the CA RIN to include expenditure for 2011-2014 which we omitted to report. We have submitted this corrected template with our RRP (RRP 5-30). This omission led the AER to primarily rely on our 2015 forecast expenditure of $27.4 million only in determining our forecast. Correcting for this shows that our expenditure over the 2011 to 2015 period is $45.5 million[8]; – Confirmed our earlier view that an increase in expenditure compared to historical levels is required to meet our obligations for reliability, safety, and quality in accordance with the NER. Much of the increase is needed to address externalities and reduce safety risks for the public and our workers in accordance with our ALARP obligation; – Revised our Business Cases to include more robust options analysis and cost benefit analysis; and – Included expenditure required to maintain the current sub-transmission network configuration following asset replacement work by AusNet Transmission Group at RTS and HTS. These projects were not included in our Regulatory Proposal. Separate Business cases for these projects are provided with this RRP. Section 5.5.7 provides further information and cross-references to supporting information, including our business cases.
VBRC	– We have removed investment for SWER replacement, included in our Regulatory Proposal and are proposing an increase in our HV ABC replacement from $19 million to $30.2 million to respond to increased failure rates resulting in fires in high bush fire areas and heightened community concern. A letter from ESV, dated 23 December 2015, supports this increased investment in HV ABC in the 2016 to 2020 period. This letter is provided as an attachment to this RRP. – We do not accept the AER's decision on REFCLs. We have submitted an updated Bushfire Mitigation Plan to Energy Safe Victoria – this includes the installation of two RECFL devises; and Section 5.5.8 provides further information and cross-references to supporting information, including our business cases.

The remainder of this section is structured as follows:

- Section 5.5.2 details our top-down conceptual framework for our Repex forecast;
- Section 5.5.3 clarifies three important misunderstandings by the AER about our Repex forecast from its Preliminary Decision;
- Section 5.5.4 recaps our forecasting method and drivers of our Repex;
- Section 5.5.5 sets out our response on Modelled Repex;
- Section 5.5.6 sets out our response on pole-top structures and SCADA;
- Section 5.5.7 sets out our response in relation to 'Other – unmodelled repex'; and
- Section 5.5.8 sets out our expenditure requirements in relation to the VBRC.

5.5.2. Top-down assessment of Repex

Table 5-15 above shows a mismatch between the AER's and our assessment of the Repex needed to maintain the network in the 2016 to 2020 regulatory period. Our forecast is 36 per cent higher than the AER's Preliminary Decision.

In order to understand this substantial difference, Table 5-17 presents the set of possible scenarios that show the relationships between:

- Current network performance and the underlying health of the network; and

[8] See RRP 5-30 CA RIN Other Un-modelled corrected

- The Repex needed to maintain the network in the 2016 to 2020 regulatory period.

Table 5-17: Top-Down Assessment Scenarios

	2011 to 2015 regulatory period		Both regulatory periods	2016 to 2020 regulatory period			
Scenarios	**Reliability**	**Network safety**	**Underlying Health of the network**	**Repex Needed (relative to 2011-15 period)**	**Asset failure rate**	**Reliability**	**Network safety**
1	Maintained	Maintained	Constant	Same	Constant	Maintained	Maintained
2	Deteriorating	Maintained	Constant	Increased	Constant	Maintained	Maintained
3	Maintained	Deteriorating	Constant	Increased	Constant	Maintained	Maintained
4	Maintained	Maintained	Deteriorating	Increased	Constant	Maintained	Maintained
5	Deteriorating	Deteriorating	Deteriorating	Significantly increased	Constant	Maintained	Maintained

Reliability and network safety are the two key performance areas that drive the bulk of Repex. Their trend in the 2011 to 2015 regulatory period is an indicator of whether sufficient Repex has been undertaken in that period, and is therefore also an indicator of the future need for Repex relative to the 2011 to 2015 regulatory period.

The underlying health of the network is an overall indicator of network condition, representing how many assets are entering their “wear out” phase where the risk of failure accelerates dramatically. Thus, it is an indicator of the proportion of assets approaching their end of life, and therefore an indicator of the future Repex needed to maintain the network.

The outcomes sought in the 2016 to 2020 regulatory period are the same for all scenarios, and are consistent with the capex objectives in the NER, namely to maintain reliability and network safety. In order to achieve this, asset failure rates will generally remain constant, noting specific and different types of asset failure drive reliability and network safety. It is thus the future Repex that needs to change in order to maintain reliability and network safety, depending on the 2011 to 2015 regulatory period performance and the underlying health of the network.

Scenario 1 describes a situation of ongoing equilibrium, where reliability and network safety are being maintained and the health of the network is constant. In these circumstances, the same level of Repex will be needed in the 2016 to 2020 regulatory period to maintain the network.

Scenarios 2, 3 and 4 describes situations where one of reliability, network safety or network health are deteriorating. Under all of these scenarios an increase in Repex would be required in the 2016 to 2020 regulatory period to maintain reliability and network safety in the next regulatory period.

Scenario 5 describes the situation where reliability, network safety and network health are all deteriorating, therefore requiring an increase in Repex in the 2016 to 2020 regulatory period to address deteriorating network health and to return network performance to target.

The AER’s top-down assessment of our Repex for the 2016 to 2020 regulatory period is partially consistent with Scenario 1. In its Preliminary Decision, the AER concludes that reliability, network safety and the health of our network were being maintained in the 2011 to 2015 regulatory period. However, the AER’s assessment of the Repex needed in the next period is 6 per cent below the levels in the 2011 to 2015 regulatory period.

Our top-down assessment reflects Scenario 5. Our reliability, network safety and network health have deteriorated in the 2011 to 2015 regulatory period, and the underlying health of our network will continue to deteriorate in the 2016 to 2020 regulatory period. Therefore, in order to return reliability and network safety to target in the next regulatory period, a significant increase in Repex will be needed.

The underlying drivers for the mismatch between the AER's and our top-down assessment of the Repex needed to maintain the network in the next period are assessed in the following sections.

5.5.3. Correcting misunderstandings in the AER's Preliminary Decision

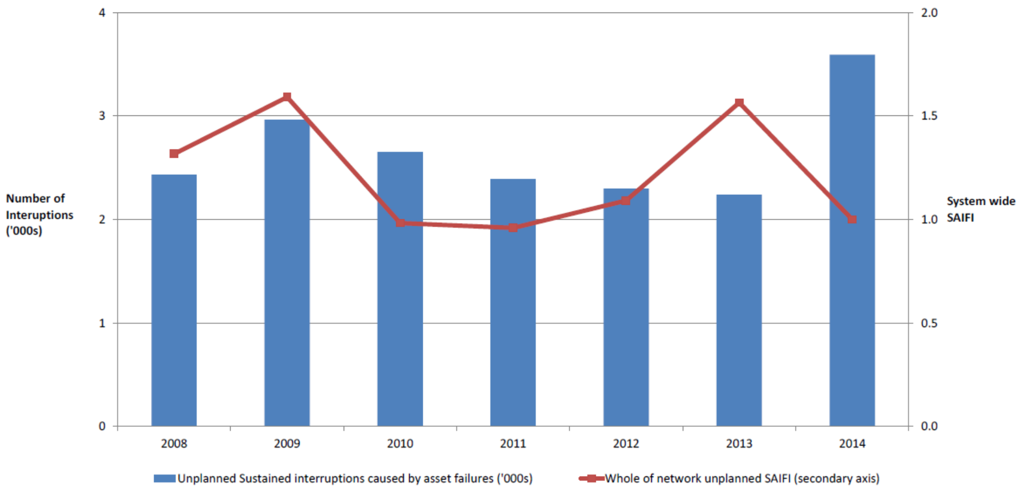
The AER has misunderstood the following matters, which it has relied on in making its Preliminary Decision:

1. Our reliability performance – the AER considers that this has not deteriorated, whereas in fact it has;
2. Our safety performance – the AER considers that this is being maintained, whereas in fact it is not; and
3. The risk of asset failure – the AER considers that this is not increasing, whereas in fact it is.

These misunderstandings are based on the AER's reliance on Figures 6-15 and 6-16 (replicated below) from the AER's Preliminary Decision.

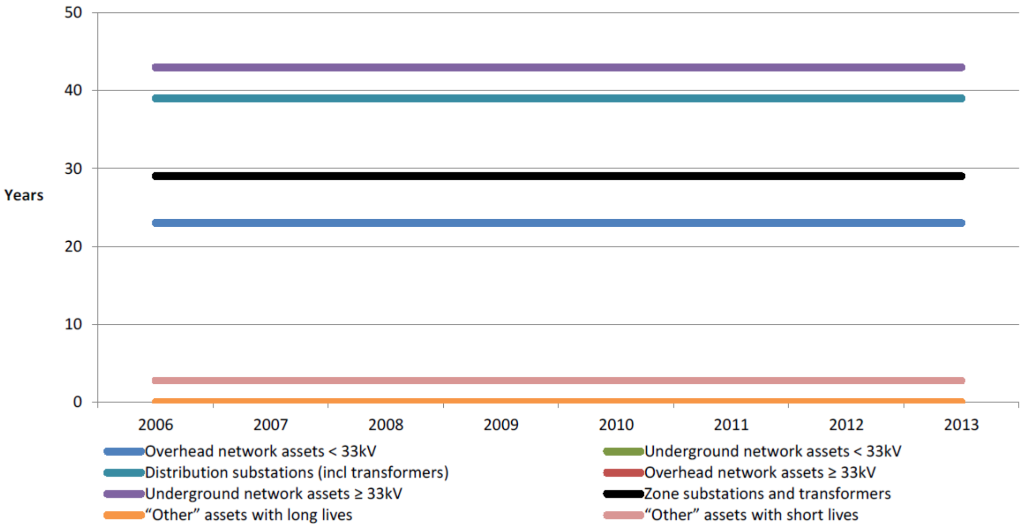
As we discuss further below, the data relied on to derive Figure 6-15 is incorrect and therefore that the AER's decisions based on this figure are also incorrect.

Figure 6-15: Relationship between system wide SAIFI and non-excluded interruptions caused by asset failures



As we also discuss further below, the AER's Preliminary Decision incorrectly assumes that the residual life metric presented in Figure 6-16 is a proxy for asset condition and therefore it incorrectly rejects our arguments that we require higher levels of Repex to address assets approaching their end of life.

Figure 6.16: Estimated residual service life network assets



Before presenting our revised Repex forecasts, it is important to correct these three misunderstandings to avoid any errors in the AER's Final Decision. We believe that these misunderstandings have contributed to the AER setting an inadequate Repex allowance in its Preliminary Decision.

Fact 1 – Our reliability performance has deteriorated

The AER appears to have misunderstood our reliability performance during the 2011 to 2015 regulatory period.

Our reliability performance has in fact been progressively deteriorating, whereas the Preliminary Decision suggests that we have maintained our reliability performance, although we note that the AER presented a contradictory view on this in its assessment of our STPIS targets.

We wrote to the AER on 11 December 2015 disagreeing with its conclusions about our reliability performance. We have included this letter at Appendix C of this RRP.

In its Preliminary Decision, the AER stated that:

> *Figure 6.15* [re-produced above] *shows that United Energy's outages due to asset failures and SAIFI have on average been flat across time. The overall stability in both of these measures indicates that the replacement practices from the last period have been sufficient to meet the capex objectives.*[9]

The AER relied on this assessment to conclude that our reliability performance has not been deteriorating and we therefore do not require an increase in Repex in the 2016 to 2020 regulatory period.

Our letter of 11 December 2015 detailed our concerns that the data relied on to derive Figure 6-15 is incorrect and therefore that the AER's decisions based on this figure are also incorrect. There are two key problems with the data that the AER relied on to derive Figure 6-15.

First, the AER's SAIFI data includes Major Event Day (MED) exemptions and applies the 2006-10 exemption criteria for the 2008-2010 period but then applies the current exemption criteria for the 2011 to 2014 period. The AER should apply the same exemption criteria for all periods in Figure 6-15 and should exclude the exemptions to provide the most appropriate network performance. This would remove large storms and provide a better view of our underlying reliability performance. We provided both in our letter to the AER and in our responses to the AER's information requests 19 and 26 the appropriate SAIFI data that we consider the AER should use in making its Final Decision. This is re-presented in Appendix C. This data applies the current exemption criteria to the years prior to 2011 and then excludes MED exemptions, so that all years are compared on a consistent basis. This data shows that both total SAIFI and equipment failure SAIFI have been deteriorating.

[9] AER, Preliminary Decision, Attachment 6, page 6-83.

Secondly, the AER's sustained interruption data is incorrect and, for the following reasons, is not an appropriate data set from which to draw conclusions on reliability:

- The data is missing some equipment failure data during 2008-2013. It was originally incorrectly classified but we corrected this in response to a query from the AER; and
- The data contains sub-transmission, HV and LV asset failures, which are not all appropriate indicators for reliability since LV asset failures are 93 per cent of all failures, but account for only 11 per cent of equipment failure SAIFI, whereas sub-transmission and HV asset failures comprise only 7 per cent of all failures, but account for 89 per cent of equipment failure SAIFI.

Therefore, the AER should use only the information for sub-transmission and HV asset failures to draw conclusions in its assessment of reliability trends. Figure 5-3 below shows our sustained outage performance based on HV and sub-transmission asset failures.

Figure 5-3: Sustained outages as a result of HV and Sub-transmission asset failures

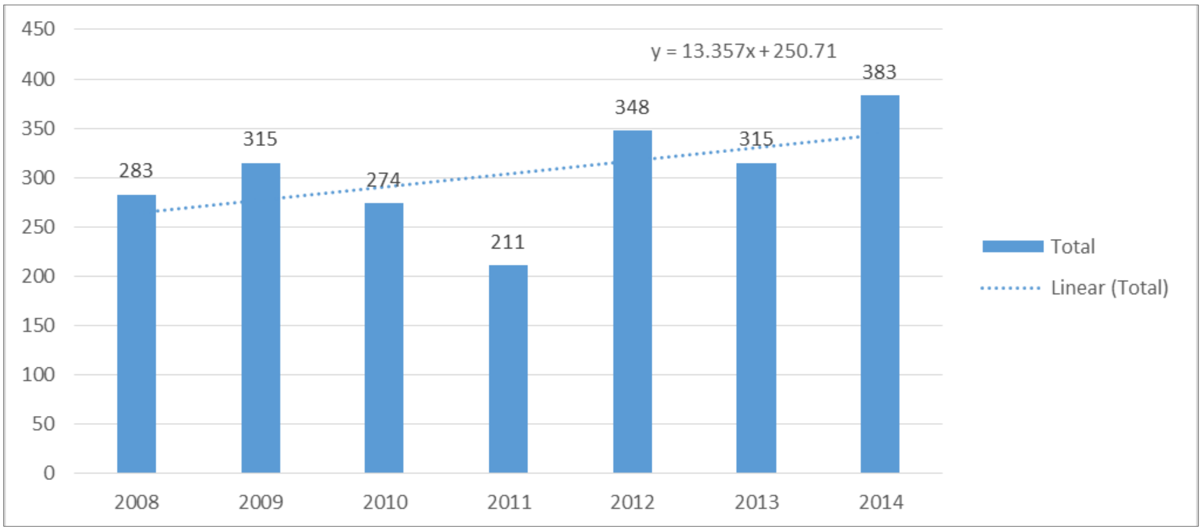


Figure 5-3 demonstrates that sustained HV and sub-transmission equipment failure is increasing at approximately 5 per cent per annum. This rate increases to nearly 10 per cent per annum if the data series commences in 2004. The increasing HV and sub-transmission equipment failure rate is consistent with our increasing network wide SAIFI.

We are also concerned that the AER's Preliminary Decision focuses exclusively on SAIFI, and fails to consider the other measures of reliability – being SAIDI and CAIDI. The AER should have regard for all of these reliability measures in its Final Decision.

The AER stated in its Preliminary Decision that:

> *...the forecast capex should be sufficient to allow United Energy to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to United Energy systematically under or over performing against its targets.*[10]

We agree with this assessment. As set out in our Regulatory Proposal, we did not meet our STPIS targets in the 2011 to 2015 regulatory period and therefore incurred STPIS penalties of approximately $40 million between 2011 and 2014. This deterioration in our performance occurred despite our Repex for the period exceeding the AER's Repex allowance by around 20 per cent. These penalties result from deterioration in all reliability measures – SAIFI, SAIDI and CAIDI – not just SAIFI.

Our letter of 11 December 2015 at Appendix C uses RIN data to show that our CAIDI is deteriorating (predominantly due to increased traffic resulting in longer times for response crews to reach site) and that the Victorian and Australian average CAIDI is also deteriorating. Indeed, CAIDI is deteriorating for 10 of 13 DNSPs

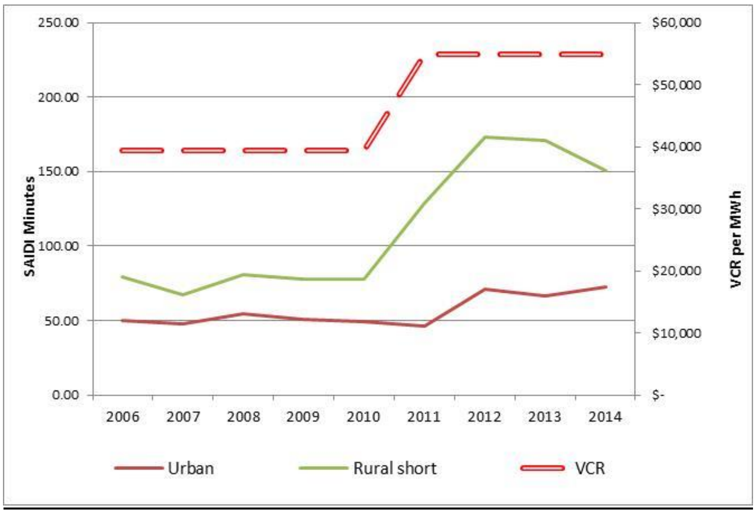
[10] AER, Preliminary Decision, Attachment 6, page 6-29.

(excluding ourselves). The AER should revise its assessment of our reliability by considering our deteriorating CAIDI and our need to address it in the 2016 to 2020 regulatory period.

As we noted above, the AER contradicts its view that we have maintained our reliability performance in its assessment of our STPIS targets for the 2016 to 2020 regulatory period. A more accurate reflection of our reliability performance is presented in Attachment 11 of its Preliminary Decision, in which the AER assesses our STPIS targets for the 2016 to 2020 regulatory period[11]:

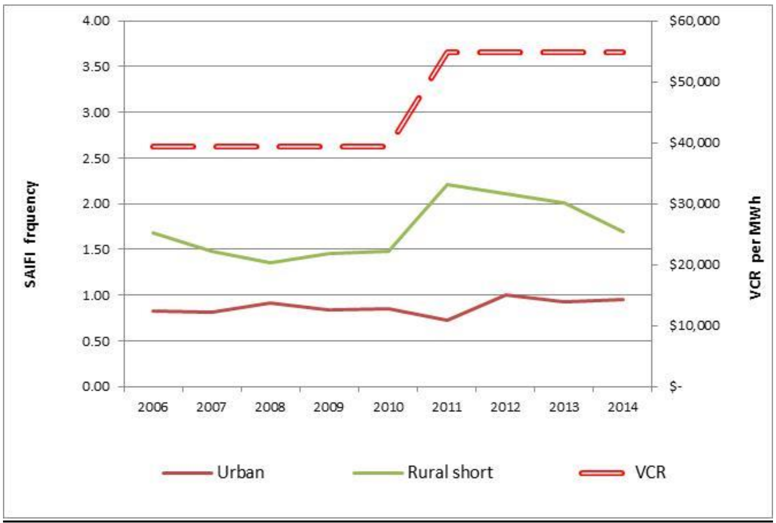
> *United Energy asserts that applying a lower VCR for capex purposes will reduce its reliability performance in 2016–20. In contrast, its historical reliability performance shows that there is limited or no immediate or close correlation between the two variables (see Figure 11.2 and Figure 11.3), at least not within 5 years from the change in VCR. That is, a 40 per cent increase in the VCR in the current period made little difference to United Energy's reliability performance. <u>In fact, United Energy's level of supply reliability under the scheme during the current period deteriorated from the previous period,</u> showing an outcome opposite to its contention.* [<u>emphasis</u> added]

Figure 11.2: Historical SAIDI



Source: AER analysis

Figure 11.3: Historical SAIFI



Source: AER analysis

[11] AER, Preliminary Decision, Attachment 11, page 11-18.

We agree with this assessment of our reliability performance from Attachment 11 of the AER's Preliminary Decision.

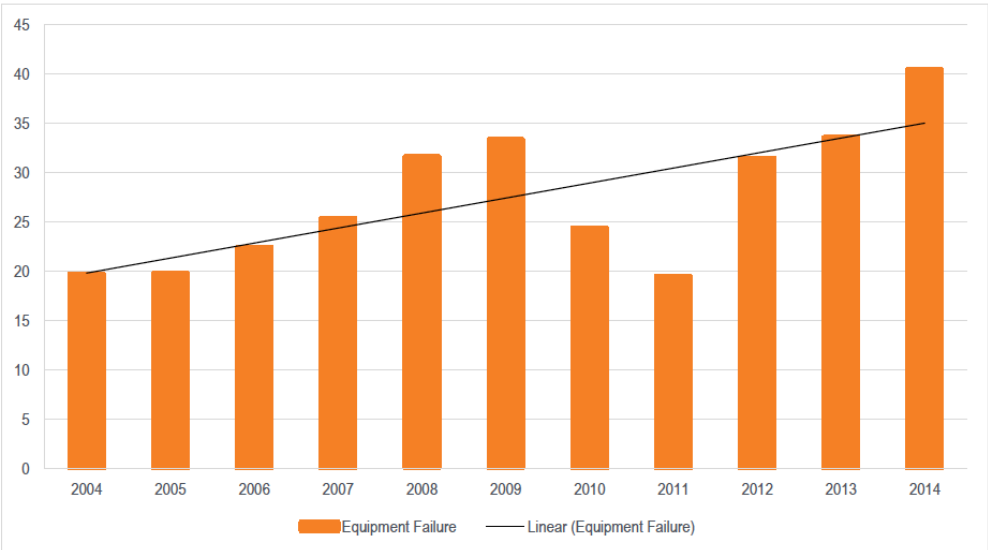
The AER's STPIS targets, which reflect historical performance, support its finding that our network reliability has in fact deteriorated. As the table below shows, in four of the six reliability measures, the AER proposes that our STPIS target should be relaxed because historical performance has worsened over the 2011 to 2015 regulatory period.

Table 5-18: STPIS reliability targets

	2011–15 regulatory period value[12]	2016-20 regulatory period value	Change in performance from last period to current period implied by 2016- 20 target[13]
Urban			
SAIDI	55.085	61.188	Deterioration
SAIFI	0.899	0.896	Steady
MAIFIe	1.074	0.918	Improved
Short rural			
SAIDI	99.151	151.602	Deterioration
SAIFI	1.742	2.018	Deterioration
MAIFIe	2.122	2.980	Deterioration

SAIDI is an important performance metric because it encompasses changes in fault frequency, the number of customers impacted, and restoration times. The AER's recognition of the deterioration in SAIDI performance is consistent with Figure 5-4 below, which focuses on the SAIDI contribution from equipment failure.

Figure 5-4: Actual and trend unplanned SAIDI due to equipment failure (minutes)



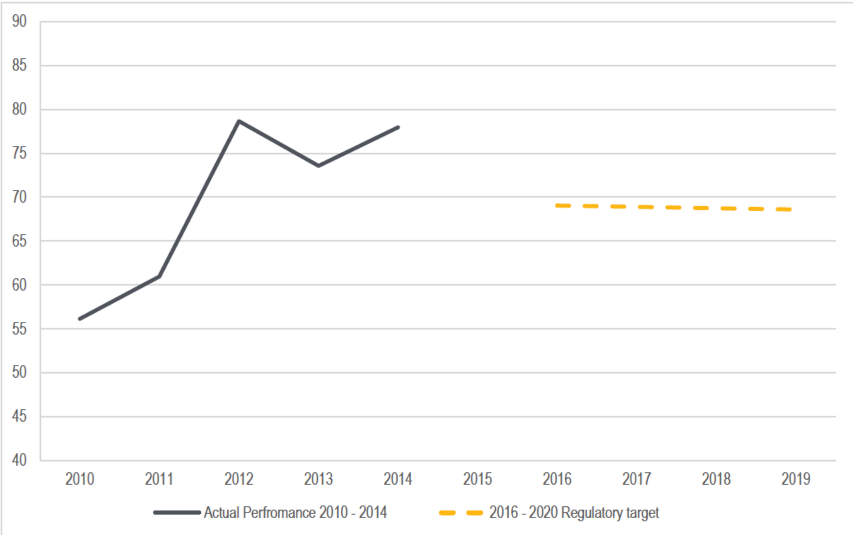
[12] AER, Victorian Distribution Determinations —Final Decision, 2011–2015, Table 15.11, page 695.

[13] AER, Preliminary Decision, Attachment 11, Table 11.2, page 11-9.

The deterioration in our SAIDI is important to our Repex forecast because:

- It has occurred despite a substantial increase in Repex from $205 million in the 2006-2010 period to $437 million in the 2011 to 2015 regulatory period (20 per cent above the AER's allowance);
- It is driven by a trend increase in the number of assets approaching end of life. As explained in relation to Fact 3 below, this trend is expected to continue in the next period, even if our Repex forecast is approved by the AER; and
- As the figure below shows, we are facing a gap between our current level of reliability performance and the AER's STPIS target, which needs to be bridged.

Figure 5-5: Actual and trend unplanned SAIDI (minutes)



In summary, the trend decline in our reliability performance shows that our Repex over the current regulatory period has been insufficient to allow us to meet our reliability objectives and that the AER should amend its Preliminary Decision on our Repex for the 2016 to 2020 regulatory period, which is below the levels we incurred during the 2011 to 2015 regulatory period. Whilst the AER has reset our STPIS reliability targets based on our historical five year average, we have a significant gap to close from our current performance to achieve our revised targets. This is for both SAIFI and SAIDI:

- Our average SAIFI over the last three years has been 1.03 interruptions whereas our STPIS target is 1.00 interruption; and
- Our average SAIDI over the last three years has been 77 minutes whereas our STPIS target is about 69 minutes.

It is important that our Repex allowance enables us to achieve our reliability targets in the 2016 to 2020 regulatory period in order that we can close the gap from our current performance.

Fact 2 – Our safety performance had deteriorated

The AER also appears to have misunderstood our safety performance during the 2011 to 2015 regulatory period.

Our network safety performance has in fact been deteriorating, whereas the Preliminary Decision suggests that we have maintained our safety performance. In its Preliminary Decision, the AER stated that:

> *…with the exception of additional funding to address the impact of new safety obligations a business as usual approach to Repex will provide United Energy with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system,*

The AER's Preliminary Decision also states that:

> *For repex categories we cannot model, historical expenditure is our best high level indicator of the prudency and efficiency of the proposed expenditure. Where past expenditure was sufficient to meet the capex criteria,*

> *it can be a good indicator of whether forecast repex is likely to reasonably reflect the capex criteria. This is due to the predictable and recurrent nature of repex*[14].

The AER goes on to say:

> *Figure 6.15* [re-produced above] *shows that United Energy's outages due to asset failures and SAIFI have on average been flat across time. The overall stability in both of these measures indicates that the replacement practices from the last period have been sufficient to meet the capex objectives.*[15]

The AER relied on this assessment to conclude that our network safety performance has not been deteriorating and we therefore do not require an increase in Repex in the 2016 to 2020 regulatory period.

Our concerns that the incorrect data relied on to derive Figure 6-15 are detailed in our discussion on Fact 1, and are also relevant for this assessment. The data for "unplanned sustained interruptions caused by asset failure" is missing some equipment failure data during 2008-2013. Further, as also noted for reliability, this is not an appropriate data set from which to draw conclusions about network safety.

In 2010, Energy Safe Victoria (ESV), the safety regulator responsible for electricity and gas safety in Victoria, developed a set of metrics to manage network safety performance in conjunction with the Victorian DNSPs. These metrics are detailed in the ESV's publication entitled "Distribution Business Electrical Safety Performance Reporting Guidelines"[16]. The metrics are defined for specific incidents considered as posing a significant safety hazard or risk. One of three broad categories of metric is asset failures.

Table 5-19 compares the total asset failures relevant for network safety as defined by ESV with the total "unplanned sustained outages due to asset failure" as used by the AER in Figure 6-15 (but corrected for missing data). This clearly demonstrates that the vast majority of "unplanned sustained outages due to asset failure" are not relevant to network safety. Therefore, the AER should revise its assessment of network safety using only asset failure data that is relevant to network safety.

Table 5-19: Asset Failures Comparison 2011- 2014

	2011	2012	2013	2014
Total Asset failures relevant to network safety (as defined by ESV)	158	277	452	433
Total Unplanned Sustained Outages due to Asset Failure (CA RIN data from Figure 6-15, corrected for missing data)	4,063	3,990	3,856	4,164

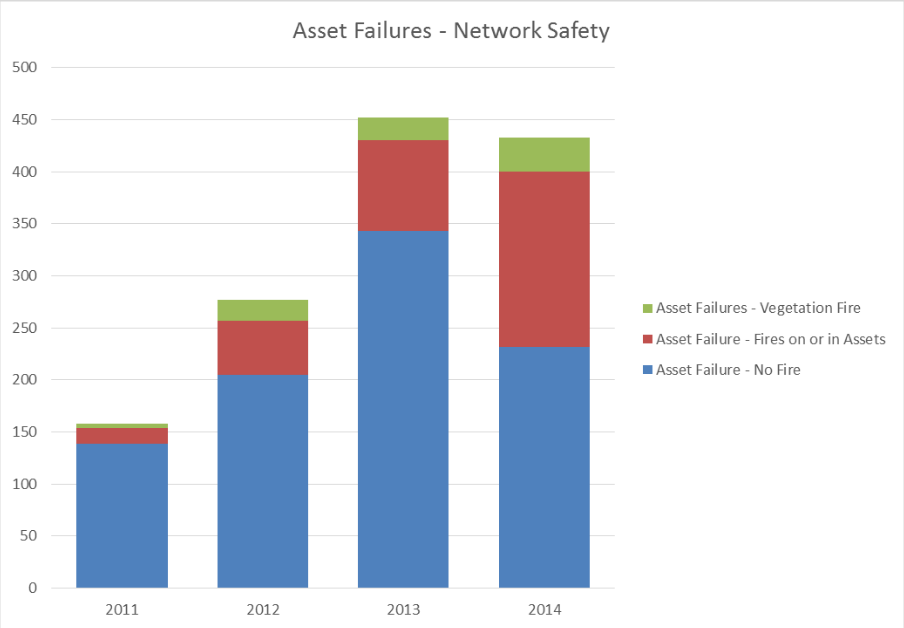
Figure 5-6 presents the total asset failures relevant to network safety, which demonstrates a clear deteriorating trend during the current period.

[14] AER Preliminary Decision, Attachment 6, page 6-77

[15] AER, Preliminary Decision, Attachment 6, page 6-83.

[16] Available at - http://www.esv.vic.gov.au/Portals/0/DB%20Electrical%20Safety%20Performance%20Reporting%20Guidelines.pdf

Figure 5-6: Asset Failures relevant for Network Safety



We are also concerned that the AER's Preliminary Decision focuses exclusively on asset failures, and fails to consider the other metrics for network safety. As outlined in our response to the AER's information request 19, we manage our network safety performance against the same metrics that ESV uses to regulate safety performance. The metrics that we use related to network assets (as opposed to work practices) are categorised as follows:

- Safety incidents that relate to asset failure:
  - Asset failures without fire;
  - Asset failure with fires on or in assets; and
  - Vegetation fires due to asset failure.
- Safety incidents that cause a fire start:
  - Asset failure with fires on or in assets;
  - Vegetation fires due to asset failure; and
  - Vegetation fires due to contact by vegetation, third party or animals.
- Safety incidents involving the public:
  - HV injections;
  - Electric shocks; and
  - Access breaches.

Figure 5-6 presents asset failures related to network safety.

Figure 5-7 and Figure 5-8 present our safety performance for fire starts and incidents involving the public. Our safety performance for both asset failures and fire starts is clearly deteriorating, whilst our performance for incidents involving the public is relatively constant.

The AER should have regard for all our safety metrics in determining our Repex allowance in its Final Decision.

Figure 5-7: Fire Starts

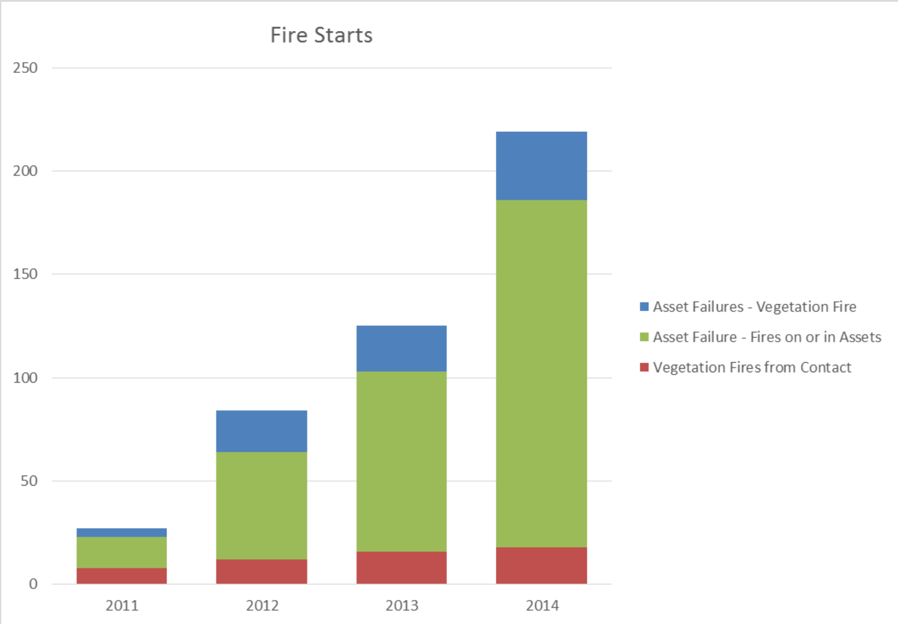
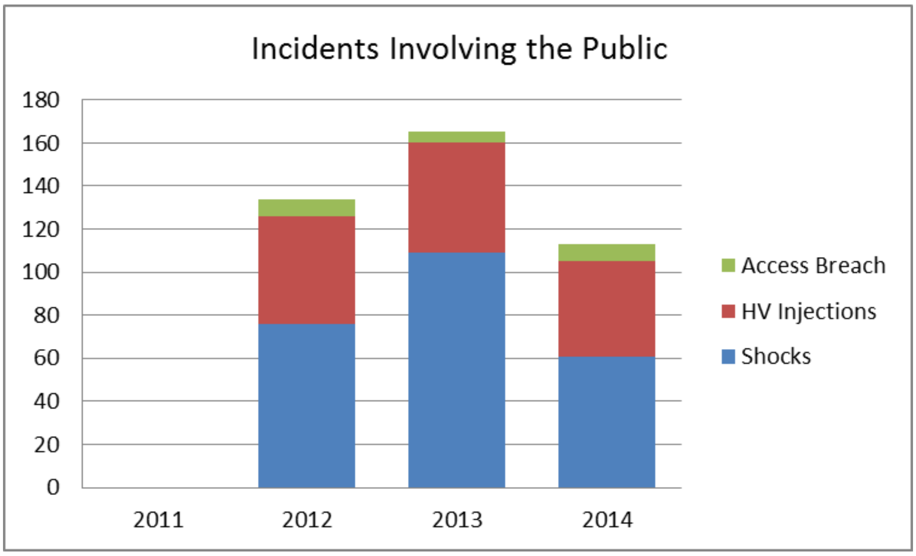


Figure 5-8: Incidents Involving the public



Finally, as we use the same safety metrics as the ESV to monitor network safety, our safety performance can be verified in ESV's report "*Safety Performance Report on Victorian Electricity Networks 2014 (July 2015)"*[17]. In the covering note to its 2014 report, the ESV states:

> *The report for the 2014 calendar year found that:*
>
> - *Asset performance is either stable or improving for four out of five businesses*
> - *The number of fires caused by network assets declined for four out of five businesses*
>
> *An overall increase in fire numbers and asset failures was driven principally by one company – United Energy.*[18]

The AER should have regard for the independent assessment of the safety regulator, ESV, in its Final Decision.

Our Network Safety Assessment provides further information in support of our safety performance and the Repex needed to meet our network safety obligations.

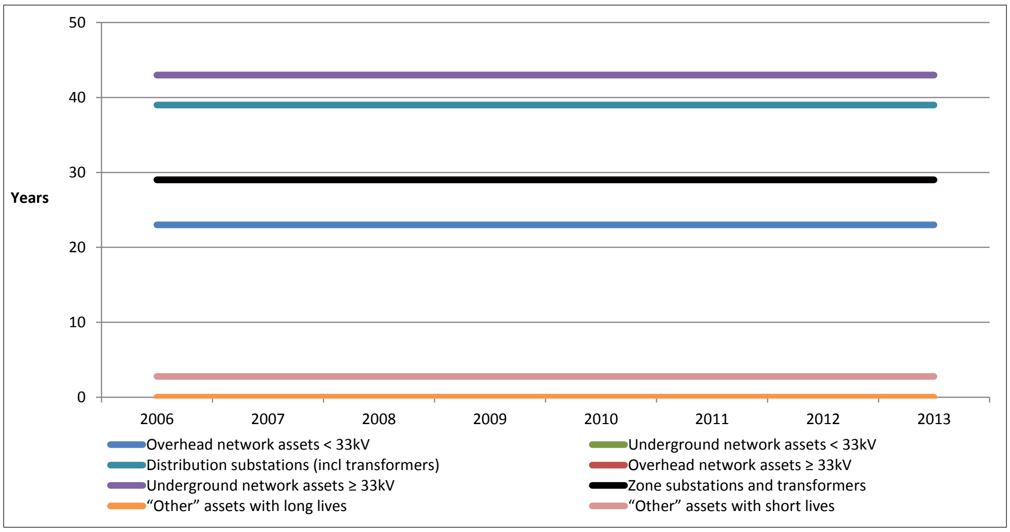
Fact 3 – We are facing an increased risk of asset failure

The AER's Preliminary Decision incorrectly assumes that the residual life metric is a proxy for asset condition. On this basis, the AER concludes that our asset condition has been maintained and therefore incorrectly rejects our position that we require higher levels of Repex to address more assets approaching their end of life.

In particular, the AER states the following about our asset lives[19]:

> *Another factor which we have considered when assessing United Energy's Repex requirements for the 2016–20 period is the trend in United Energy's residual asset life across time. We are satisfied that residual service life is a reasonable high-level proxy for asset condition. Asset condition is a key driver of replacement expenditure.*
>
> *Figure 6.16 shows that United Energy's residual asset lives have been flat over the period 2006–2013. This means that, on average, United Energy's network assets are staying the same age.*

Figure 6.16: Estimated residual service life network assets



> *……….the flat trend in residual lives (where age is a proxy for asset condition) suggests that the health of United Energy's asset base has been maintained.*

[17] Found At http://www.esv.vic.gov.au/Portals/0/about%20esv/FINAL%202014%20Safety%20Performance%20Report%20on%20Victorian%20Electricity%20Networks.pdf

[18] Safety Performance Report on Victorian Electricity Networks 2014. - ESV July 2015

[19] AER, Preliminary Decision, Attachment 6, page 6-84.

The AER also refers to concerns raised by Victorian Greenhouse Alliances (VGA)[20] regarding the 'reduced average asset age for most asset categories' and the Consumer Challenge Panel (CPP), which commented:[21]

> *The current levels of capex have not resulted in a deterioration of residual asset lives, which the CCP considers implies there is no need for an increase in Repex over current expenditure levels*.

We accept the intuitive appeal of treating changes in residual asset lives as a proxy for asset condition. However, the key driver for asset replacement is the volume of assets approaching their end of life. This information cannot be obtained from the average residual life metric. In fact, the AER recognised in its Preliminary Decision the limitations of its residual life analysis, when it noted:

> *We acknowledge limitations exist when using estimated residual service life to indicate the trend in the underlying condition of network assets. Large volumes of network augmentation and connections can result in a large stock of new assets being installed in the network, which may bring down the network's average age. In this way, the residual service life of the assets may increase without necessarily addressing any underlying asset condition deterioration.*[22]

Despite this acknowledgment, the AER concluded that[23]:

> *The flat trend in residual lives (where age is a proxy for asset condition) suggests that the health of United Energy's asset base has been maintained.*

This conclusion cannot be drawn from the residual life metric, as fundamentally the metric reflects the volume of asset entering the "wear out" phase, where assets approach their end of life and the risk of failure increases significantly. It is this volume of network assets at high risk of failure that primarily drives the need for replacing assets to maintain reliability and network safety.

We have developed an independent and robust model of the underlying health of the network, to be applied primarily in a top-down assessment of the total Repex needed to maintain reliability and network safety. In considering the basis for the model:

- Residual life and average age were both rejected primarily for the reasons outlined above;
- Conditions Based Risk Management (CBRM) and Weibull analysis, whilst both being well established methodologies used across many industries, require extensive data not readily available for all asset classes, and are already used to prepare bottom up assessments for specific asset classes; and
- Assets passing an age threshold was selected, using age as a proxy for condition, as it purely focuses on assets at the end of their life cycle that are entering the wear out phase, rather than the whole asset base. Weibull lives are used where available for an asset class, otherwise the economic life is used. The data for the model is readily available in RIN's provided to the AER.

The model uses an age threshold of 85 per cent of the end of asset life, chosen because it is the age where the rate of asset failure is predicted to rapidly increase, based on typical Weibull characteristics and CBRM health index methodology.

The results from the model at the overall network level are presented in Figure 5-9. This clearly shows that the proportion of assets reaching the wear out phase have increased over the last ten years and are forecast to increase in the next six years (from the start of 2015 to the end of 2020) despite forecast replacement expenditure. This demonstrates the underlying health of the network has been and will continue to deteriorate.

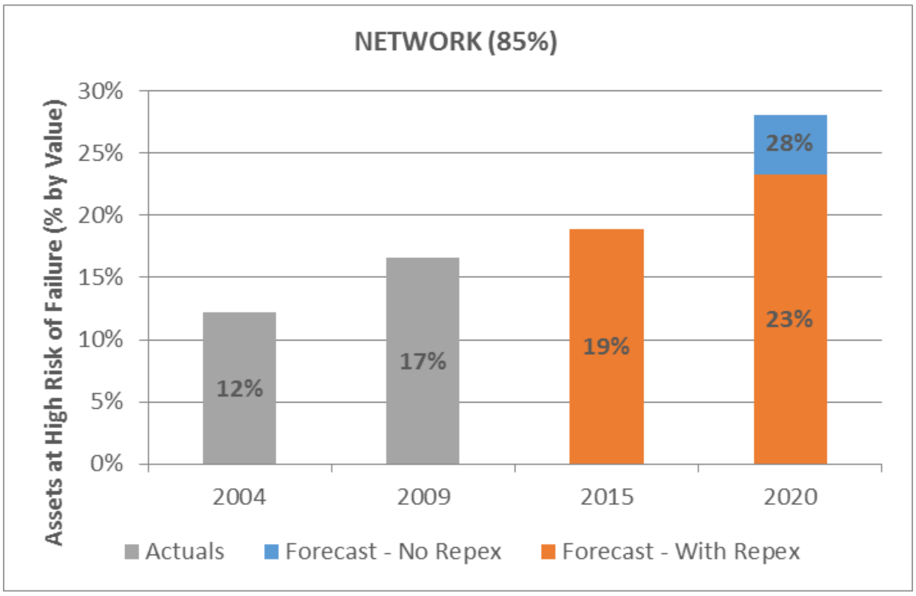
[20] AER, Preliminary Decision, Attachment 6, page 6-26.

[21] Ibid, page 6-26.

[22] Ibid, page 6-149.

[23] Ibid, page 6-84.

Figure 5-9: Assets at high risk of failure – whole network



If we did not undertake replacement, the proportion of assets at high risk of failure would increase from 19 per cent to 28.1 per cent, or around $800 million. For our proposed Repex, which includes $408 million of asset replacement for the 2016 to 2020 regulatory period (including modelled and unmodelled asset classes and ZSS Primary Assets replacement), the proportion of assets at high risk of failure will still increase to 23.3 per cent. Noting our equivalent asset replacement during the 2011 to 2015 period was $375 million, the forecast ongoing deterioration in network health strongly supports the need for an increase in asset replacement capex and overall Repex in the 2016 to 2020 period to maintain reliability and network safety.

The above figure is generally consistent with the AER's Figure 6.15 (presented above), which shows a flat average age profile from 2006 to 2013.[24] As alluded to by the AER, the different perspective is explained by the addition of new assets from augmentation and connections, which tend to maintain the residual life and average age profile. However, these profiles mask the growing number of assets that are approaching their end of life.

Our model of assets at high risk of failure is a robust indicator of network health because:

- It is soundly based on the risk of asset failure;
- It is built from data from the CA RIN which is readily available and transparent;
- It is not sensitive to specific inputs, such as asset lives, unit rates or the age threshold selected; and
- Has been validated against historical network performance.

Our application of this model indicates that the underlying health of the network will continue to deteriorate in the 2016 to 2020 regulatory period. This supports our view that we need increased Repex in the next regulatory period to maintain reliability and network safety.

We have provided the model and our detailed Assets at High Risk of Failure Assessment (UE PL 2044) to the AER with our RRP.

5.5.4. Our Repex forecasting method and key expenditure drivers

We described in our "Capital Expenditure Overview Paper – Replacement" document and Asset Life Cycle Strategies (LCS) that we submitted with our Regulatory Proposal the methodology we used to prepare our Repex forecast. In summary, the objective of our methodology is to produce a Repex forecast that will enable us to meet our safety, reliability, power quality and environmental obligations efficiently and prudently. Importantly, Repex is much broader in scope than just asset replacement.

[24] AER, Preliminary Decision, Attachment 6, page 6-84.

Our LCS for each asset class ensures our forecast investment addresses our compliance obligations in accordance with good engineering practice. For components of Repex not driven by reliability or safety obligations, such as power quality and environmental expenditure, investment is focused on maintaining existing levels of compliance.

In response to requests by the AER, we have submitted with this RRP our *Network Reliability Assessment* and *Network Safety Assessment*, which provide further detailed explanations of our approach to optimising expenditure across asset classes and dedicated programs (in Other – Unmodelled and VBRC Safety categories) by presenting opportunities for trade-offs. This ensures we meet our reliability and safety objectives at least cost. The cornerstone of each assessment is a one page summary that presents the actual performance and repex by category for the current period and the forecast performance and repex by category for the next period. This provides a clear line-of-sight on how trade-offs and optimisation have been achieved across the various reliability and safety metrics.

The reliability and safety assessments are iterative processes, as they require optimisation across multiple metrics, and particularly since asset replacement is the primary lever for maintaining both reliability and network safety.

Our Asset at High Risk of Failure (HROF) Assessment has been applied in conjunction with the reliability and safety assessments. The HROF metric for an asset class has been used to check the proposed asset replacement and asset inspection and conditions monitoring plans that enable asset to be replaced as close as possible to their end of life.

Table 5-20 presents expenditure types, forecasting methods and expenditure drivers that comprise our Repex.

Table 5-20: Repex Forecasting Methodology and Expenditure Drivers

Expenditure category	Forecasting method	Expenditure drivers
1. Modelled Repex	– Bottom-up – Weibull, Condition-based, trend, project specific – Top-down – Reliability, Safety and High Risk of Asset Failure (HROF) assessments	– Maintain reliability by addressing equipment failure risk (SAIFI). – Maintain safety. – Address increasing assets at HROF.
2. Pole top / SCADA	– As above	– Maintain reliability by addressing equipment failure risk (SAIFI). – Maintain safety.
3. Unmodelled Repex	– Top-down – Reliability, Safety and High-risk of Asset Failure assessments	
a. ZSS primary asset replacement	– Bottom-up – Weibull, Condition-based, trend, project specific	– Maintain reliability by addressing equipment failure risk (SAIFI). – Maintain safety.
b. Non-VBRC safety (CCTV)	– Project justification	– Maintain safety by addressing increasing security and access breach risk.
c. Operational Technology		
(i) OT safety	– Project justifications – ALARP assessments	– Maintain safety by addressing increasing security and access breach risk. – Reduce electric shocks & bushfire risk as per ALARP obligation.
(ii) OT reliability	– Project justifications, ranked and selected in the Reliability Assessment	– Maintain reliability by addressing deteriorating restoration times and hence CAIDI (e.g. fault location identification).
(iii) OT other	– Project justifications	– Facilitate capex efficiency in specific parts of the capex program. – Pilot new, innovative technologies (REFCLs previous example).
d. Reliability	– Project justifications, ranked and selected in the Reliability Assessment	– Maintain reliability by reducing the number of faults (e.g. animal proofing), reducing the number of customers impacted by faults (e.g. ACR's & RCGS's), and reducing restoration times (e.g. communications upgrades).
e. Environment	– Project justifications	– Maintain current levels of environmental compliance by addressing externalities including customer complaints, EPA directions, and revised legislation.
f. Power Quality	– Project justifications	– Maintain current levels of power quality compliance, by addressing the ongoing increase in solar PV installations.
g. Terminal station redevelopment	– Project justifications	– Maintain system security by replacing assets triggered by terminal station redevelopments initiated by AusNet Services.
4. VBRC Safety	– Bushfire mitigation ALARP risk assessment – VBRC requirements – Project justifications – Top-down – Safety and High Risk of Asset Failure Assessments	– Maintain safety by addressing the increasing risk of bushfires due to escalating premature failures of HV ABC cable. – Reduce bushfire risk arising from the supply network as per our ALARP obligation.

Table 5-21 overviews our revised Repex forecasts for the next regulatory period. It also details the supporting documents that we are providing as part of this RRP that justify the efficiency and prudency of our forecasts.

Table 5-21: Revised Repex forecast for 2016-20 and supporting documents ($M, Real 2015)

	Actual 2011-15	Regulatory Proposal 2016-20	Preliminary Decision 2016-20 *	RRP 2016-20	Supporting Documents provided with this RRP
1. Modelled					– Nuttall Consulting report - AER repex modelling – addendum - consideration of AER preliminary decision – A report to UED, December 2015 – Lifecycle Strategies (LCS) submitted with Regulatory Proposal – Capital Expenditure Explanatory Statements (CEES) submitted with Regulatory Proposal – Network Reliability Assessment – Network Safety Assessment – Asset High Risk of Failure Assessment – Letter dated 11 December 2015 from Andrew Schille of UE to Chris Pattas of AER re Network Safety and Reliability
a. Poles	35.8	39.4	215.8	38.7	
b. Overhead conductors	0.3	1.4		1.4	
c. Underground cables	38.4	44.3		43.5	
d. Service Lines	69.3	34.2		33.6	
e. Transformers	31.9	70.6		69.2	
f. Switchgear	59.2	81.9		80.4	
Total Modelled	**234.8**	**271.9**	**215.8**	**266.8**	
2. Pole top structure and SCADA					– No additional documents - we have accepted the AER's Preliminary Decision
Total Pole top structure and SCADA	**132.3**	**133.7**	**127.4**	**131.4**	
3. Other Unmodelled					– Network Reliability Assessment – Network Safety Assessment – Asset High Risk of Failure Assessment – Letter dated 11 December 2015 from Andrew Schille of UE to Chris Pattas of AER re Network Safety and Reliability
a. ZSS primary asset replacement	8.2	10.4	7.3	10.1	– Updated CEES - Zone Substation Capacitor Banks, Earth Grids, Neutral Earth Resistor, Transformer Instrumentation – Updated CEES - Zone Substation Buildings
b. Non-VBRC Safety Projects	1.4	6.5	0.4	6.4	– Intelligent Secure Substation Asset Management (ISSAM) (CCTV) UE PL 2401
c. Operational Technology	4.1		4.0		
(i) OT safety		19.7		24.5	– Service Mains Deterioration Field Works PJ1385 – In Meter Capabilities (IMC) PJ1386 – Light Detection And Ranging (LiDAR) Asset Management PJ1400 – OT Security PJ1500 – DNSP Intelligent Network Device PJ5002

	Actual 2011-15	Regulatory Proposal 2016-20	Preliminary Decision 2016-20 *	RRP 2016-20	Supporting Documents provided with this RRP
(ii) OT reliability		6.9		6.8	– Distribution Fault Anticipation Data Collection and Analytics (DFADCAA) PJ1599 – Fault Location Identification and Application Development PJ1600
(iii) OT other		11.4		10.2	– Dynamic Rating Monitoring Control Communication (DRMCC) PJ1413 – Test Harness PJ1398 – Pilot New and Innovative Technologies PJ1407
d. Network Reliability	24.1	36.4	12.0	35.8	– Network Reliability Assessment UE PL 2304 – Section 7
e. Environment	2.4	5.3	0.3	5.2	– New CEES – Environment
f. Power Quality	5.3	8.2	0.8	8.0	– New CEES - Power Quality Maintained
g. Terminal Station Redevelopment	0.0	0.0	0.0	5.2	– Terminal Station Redevelopment HTS - UE-DOA-S-17-002 – Terminal Station Redevelopment RTS - UEDO-14-003
Total Unmodelled	**45.5**	**104.7**	**27.3**	**112.2**	
4. VBRC Projects					– Bushfire ALARP assessment – Asset High Risk of Failure Assessment
a. HV Aerial Bundled Cable	1.0	19.0	18.6	30.2	– HV Aerial Bundled Cable Strategic Analysis Plan - UE PL 2053
b. Rapid Earth Fault Current Limiter (REFCL)	2.9	20.9	0.0	7.5	– DMA and MTN ZSS REFCL Installation
c. Other	20.5	34.8	16.2	15.6	
Total VBRC Projects	**24.4**	**74.8**	**34.8**	**53.3**	
Total Repex	**437.0**	**585.1**	**405.4**	**563.6**	

* AER Preliminary Decision includes its adjustment for real cost escalation

Our revised Repex proposal for 2016 to 2020 is $126.6 million greater than our actual Repex in the 2011 to 2015 regulatory period. The increase can be broken down by driver as follows:

- $51.5 million - to maintain reliability and network safety and address deteriorating network health:
  - $33.0 million in asset replacement; and
  - $18.5 million in specific reliability projects.
- $54.4 million - to reduce safety risk as per VBRC and ALARP obligations, and address safety externalities, such as increasing security risk:
  - $28.9 million for VBRC safety;
  - $11.1 million to address increased security and access breach risk;

  - $8.0 million to reduce electric shocks to the public by 50 per cent, as per our ALARP obligation; and
  - $6.4 million for LiDAR to reduce bushfire and other risks.
- $10.7 million - to address other externalities:
  - $2.7 million to address power quality issues resulting from increased PV to be installed;
  - $2.8 million to address environmental externalities like urban encroachment on substations; and
  - $5.2 million to address terminal station redevelopment works initiated by AusNet Services.
- $10.2 million – for other drivers:
  - $3.2 million capex efficiency; and
  - $7.0 million piloting new technologies.

This bottom-up assessment is consistent with our top-down assessment presented in section 5.5.2. The increase of $51.5 million to address deteriorating reliability, safety and network health and close the gap between current performance and our targets for next period is approximately 13 per cent above the equivalent expenditure for the current period.

It is important to note that $65.1 million of the increase is attributable to reducing the network safety risk (meeting our VBRC and ALARP obligations) and addressing externalities.

In the following sections we explain and justify our forecasts for each of our four capex categories.

5.5.5. Key Category 1 – Modelled Repex

Table 5-22 details our revised Modelled Repex forecast, as well as the AER's Preliminary Decision and our Regulatory Proposal. It shows that the AER has reduced the forecast in our Regulatory Proposal from $271.8 million to $215.8 million over the 2016 to 2020 regulatory period, or by 21 per cent. We have now revised our Repex forecast to $266.8 million.

Table 5-22: Modelled Repex 2016-20 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	47.6	58.1	60.5	58.1	47.5	271.8
AER Preliminary Decision *	n/a	n/a	n/a	n/a	n/a	215.8
RRP	47.1	56.7	58.6	57.2	47.1	266.8

* AER Preliminary Decision includes its adjustment for real cost escalation

Table 5-23 shows this breakdown for 2016 to 2020 for the six asset types that comprise Modelled Repex.

Table 5-23: Modelled Repex by asset type – AER's Preliminary Decision compared to UE Regulatory Proposal and RRP ($M, Real 2015)

Component	Actual 2011-15	Regulatory Proposal 2016-20	AER Preliminary Decision 2016-20 *	RRP 2016-20
Poles	35.8	39.4	215.8	38.7
Overhead Conductors	0.3	1.4		1.4
Underground Cables	38.4	44.3		43.5
Service lines	69.3	34.1		33.6
Transformers	31.9	70.6		69.2
Switchgear	59.2	81.9		80.4
Total Modelled	**234.8**	**271.8**	**215.8**	**266.8**

* AER Preliminary Decision includes its adjustment for real cost escalation

The AER's Preliminary Decision to reject our forecast and substitute it with its own was based on the results of its application of its Repex model using historical unit rates.

For the reasons discussed below, we have maintained in this RRP the forecast that we presented in our Regulatory Proposal, subject to minor adjustments for the application of cost escalations.

As explained in section 5.5.4, we developed our forecasts based on our LCS documents for each asset type. These documents were submitted with our Regulatory Proposal. The methodology set out in these documents (summarised in Table 5-20) ensures that our Repex forecasts reflect the efficient and prudent costs of satisfying the capex objectives in the NER.

We have submitted with this RRP three documents that explain our top-down assessment of our *Modelled Repex – Network Reliability Assessment*, *Network Safety Assessment* and *Asset High Risk of Failure Assessment* (and the associated model). These new documents set out how we optimise expenditure across asset classes and investment types to achieve the reliability and safety objectives at the least cost.

In addition, we have validated our Modelled Repex forecast by applying the AER's Repex model. This analysis is contained in a report from Nuttall Consulting. This report has been updated from that which we provided to the AER with our Regulatory Proposal.

In making its Final Decision on our 2016 to 2020 Repex allowance, the AER should have regard to the forecasting method and expenditure justifications that we used to derive our forecast. We are concerned that the AER determined a substitute Repex forecast in its Preliminary Decision by relying on the outcomes of its application of its Repex model and chose the lowest cost scenario based on historical unit costs.

We do not accept the AER's Preliminary Decision. We maintain our view that our original forecast is appropriate and request that the AER revisit its analysis in making its Final Decision, having regard for:

- Nuttall Consulting's further modelling – this confirms that our forecasts derived using forecast unit costs produce a modelled Repex outcome that is broadly consistent with our internal bottom-up forecast. It also suggests that using the forecast unit costs is justifiable for deriving the Modelled Repex forecast and that using the historical unit costs relied on by the AER in its Preliminary Decision could be significantly understating our required Repex; and
- Our forecast unit costs – the AER has inappropriately rejected our forecast unit costs and instead has used historical unit costs. We consider forecast unit costs must be preferred because they are consistent with the proposed work volumes and mix. Our unit costs are sourced from a competitively tendered contract, which the AER has previously reviewed and assessed to be efficient.

We discuss these two matters further in turn.

Updated modelling by Nuttall Consulting

We engaged Nuttall Consulting to review the AER's Repex modelling. This analysis is contained in an Addendum to Nuttall Consulting's original report[25]. This Addendum contains revised Repex analysis which:

- Is based on the same five year calibration period as was applied by the AER, being 2011 to 2015;
- Incorporates pole staking data provided to the AER in response to the AER's information requests;
- Includes only the asset categories covered by the AER;
- Undertakes revised modelling based on three key scenarios, being (i) historical unit rates (ii) forecast unit rates (iii) benchmark unit costs; and
- Undertakes revised modelling for the period 2015 to 2019 (consistent with the AER's analysis) as well as the period 2016 to 2020, which is the appropriate period as it is our 2016 to 2020 regulatory period.

Nuttall Consulting produces revised capex forecasts for each modelled scenario that are significantly higher than the AER's equivalent forecasts. In particular:

- For the scenario using historical unit rates, Nuttall Consulting's analysis is $31 million higher than the AER's equivalent analysis (adjusted for the 2016 to 2020 period), which it relied on in its Preliminary Decision; and
- For the scenario using forecast unit costs, Nuttall Consulting's analysis is $32 million higher than the AER's equivalent studies (adjusted for the 2016 to 2020 period), which it relied on in its Preliminary Decision.

Nuttall Consulting finds that:

> *…….. the AER's application of the repex model to set an alternative estimate has its limitations. This is most notable with regard to:*
>
> - ***categorisation limitations** - the predefined asset categories in the RIN (i.e. tables 5.2.1 and 2.2.1), which have the potential to capture a range of activities that could have significantly different unit costs (and possible asset life distributions)*
> - ***calibration data limitation** – the repex allocation rules in the RIN, which have the potential to mean that the replacement of assets (that were very near to their end-of-life) and associated expenditure is allocated to other expenditure categories (e.g. augmentation) if this was seen as the primary driver*
> - ***weakly age-related drivers** – the repex model assumes all asset are replaced due to a driver that is correlated with the age of the asset, but some replacements may be driven by factors that correlate better with other factors*
> - ***aggregation limitation** - the use of an aggregate repex measure across all covered asset groups, which has the potential to lead to inaccuracies if the various over- and under-forecasts at the more granular level (due to other model limitations) do not approximately cancel.*[26]

Nuttall Consulting goes on to say that:

> *………these limitations mean that it has to be recognised that the method used by the AER to accept or reject a DNSP's repex forecast, via the repex model, is subject to a type of false positive and false negative finding. By this I mean:*
>
> - *a false positive finding would be the <u>acceptance</u> of the DNSP's forecast because it was below the alternative estimate, when the DNSP's forecast is not in accordance with the NER*[27]
> - *a false negative finding would be the <u>rejection</u> of the DNSP's forecast because it was above the alternative estimate, when the DNSP's forecast is in accordance with the NER.*

[25] AER Repex modelling: Assessing UED's replacement forecast" April 2015

[26] Nuttall Consulting, *Nuttall Consulting report - AER repex modelling – addendum - consideration of AER preliminary decision – A report to UED*, December 2015, pages 10-11

[27] Note, to avoid confusion, I have reversed the meaning that is commonly used when applying these terms to medical testing, where a positive finding from the test is a negative result for the patient. Here a positive finding from the test is a positive results for the DNSP.

> *It is particularly important to recognise the possibility of these findings when the alternative estimate is used to define a substitute forecast when the DNSP's forecast has been rejected.*
>
> ***Enhanced acceptance/rejection testing via the repex model – the conflict test***
>
> *To reduce the possibility of an incorrect finding because of these limitations, the AER's application of the repex model has to be overlayed with additional considerations.*[28]

Nuttall Consulting concludes that:

> *In UED's case, it appears that it has good cause to consider that the repex model assessment would fail such a conflict test, meaning that there is a reasonable possibility that the AER's finding is a false negative.*
>
> *The repex model assessment suggests that UED's forecast unit costs are much higher than its historical unit costs and the AER's benchmark unit costs. However, this finding conflicts with findings elsewhere. Most notably:*
>
> - *UED is one of the top performers in the AER's latest benchmarking report, where it is typically in the top 2 or 3 for most reported measures – suggesting it and its unit costs are efficient*
> - *UED has advised that the unit costs associated with replacement activities are based directly on competitively tendered service agreements, which the AER reviewed in arriving at UED's current decision and found at that time that these agreements passed its presumption test and so could be presumed to reflect efficient costs*[29] *The AER has also accepted the suitability of the contracted unit costs in its preliminary decision when assessing specific programs; for example, in its assessment of UED's HV ABC program as part of its review of UED's bushfire safety-related capex.*
> - *UED has indicated in its forecasting methodology descriptions that it derived its repex forecast by forecasting replacement volumes and then applying the unit rates from these service agreements. The AER conducts a review of forecasting methodologies as one of its assessment techniques but this review does not seem to have raised a significant concern with UED's forecasting methodology with regard to its sourcing, calculation and use of unit cost estimates.*
>
> *It is beyond the scope of this review to confirm that UED's methodology to prepare and use its forecast unit costs is appropriate, but assuming all three points above are valid then it seems reasonable to conclude that UED's forecast unit costs should reflect efficient costs. Consequently, it seems reasonable to conclude that the assessment would fail the conflict test, and so, further investigations should have been applied to determine what was driving the apparently conflicting results and in turn what the appropriate alternative estimate should be.*[30]

This supports the view that it is valid to rely on the forecast unit costs and that the AER should not substitute our forecast with an alternative based on historical unit rates.

Choice of unit costs in Repex analysis

In its Preliminary Decision, the AER noted that Nuttall Consulting's modelling scenarios ranged from 16 per cent below our Repex forecast to 3 per cent above the forecast – largely driven by the choice of unit costs which has material impact on the AER's Repex model outputs. The AER's Preliminary Decision correctly highlights that:

> *Nuttall Consulting noted the change to its forecast unit cost parameter had the most significant effect on outcomes. The results suggesting that the unit costs United Energy is using for its forecast are materially higher, in aggregate and on average, than it has incurred in recent history.*[31]

[28] Nuttall Consulting, page 11

[29] Page 51-52, Appendix H, outsourcing and related party transactions, Victorian distribution determination 2011-2015, draft decision

[30] Nuttall Consulting, page 13

[31] AER, Preliminary Decision, Attachment 6, page 6-76.

The AER concluded in relation to unit costs:

> *We compared United Energy's historical unit costs to benchmark unit costs.*
>
> *[..]*
>
> *When applied in the repex model average benchmark unit costs produced an almost identical forecast for the modelled categories compared to using United Energy's own historical unit costs. This suggested United Energy's historical unit costs are more likely to reflect a realistic expectation of input costs than the unit costs it forecasts.*[32]

Nuttall Consulting's revised analysis shows that the Repex model supports our Repex forecasts if our forecast unit costs are adopted.

Our unit costs are sourced from competitively tendered outsourced contracts. These contractual arrangements were examined in detail by the AER during the EDPR for the 2011 to 2015 regulatory period. The AER reached the following conclusion about the efficiency of our unit costs:

> *The AER as stated in the draft decision considers that United Energy conducted a reasonably competitive tender process. As a result the unit costs for outsourced services arising from this tender are likely to reasonably reflect efficient costs.*[33]

On efficiency grounds, there is no reasonable basis for the AER to revisit and reject prices that have been set in a competitive market, especially as the AER has previously determined that the prices satisfy the NER requirements.

The AER should not prefer benchmarked unit costs just because they are lower than our forecast unit costs. This approach would effectively impose an ex post review on our competitively tendered rates, thereby exposing our shareholders to asymmetric risk (no upside for low rates, but downside for high rates). It also fails to recognise that our contract scope is much broader than the six Repex categories. A limited benchmark that only focused on a small number of services would also expose us to asymmetric risk, as no credit is given for other services that may benchmark exceptionally well.

5.5.6. Key Category 2 – Poletop Structures and SCADA

Table 5-24 details our revised Poletop Structure and SCADA Repex forecast in response to the AER's Preliminary Decision and the forecast in our Regulatory Proposal.

Table 5-24 shows that the AER accepted our Regulatory Proposal. The difference between our Regulatory Proposal and the AER's Preliminary Decision only relates to cost escalation. We have accepted the AER's decision to apply zero materials escalation and a lower labour rate.

We accept the AER's forecast in its Preliminary Decision for Poletop Structure and SCADA Repex.

Table 5-24: Poletop structures and SCADA 2016-20 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	28.6	26.8	25.7	24.9	27.7	**133.7**
AER Preliminary Decision *	n/a	n/a	n/a	n/a	n/a	**127.4**
RRP	28.3	26.2	24.9	24.5	27.5	**131.4**

* AER Preliminary Decision includes its adjustment for real cost escalation

32 AER, Preliminary Decision, Attachment 6, page 6-73.

33 AER, Final Decision, Victorian electricity distribution network service providers, Appendices, October 2010, page 137

5.5.7. Key Category 3 – Unmodelled Repex

Table 5-25 details our revised Unmodelled Repex forecast in response to the AER's Preliminary Decision and the forecast in our Regulatory Proposal. It shows that the AER cut the forecast in our Regulatory Proposal by 74 per cent. We do not accept the AER's Preliminary Decision and maintain the forecast presented in our Regulatory Proposal for the reasons set out below.

Table 5-25: Unmodelled Repex 2016-20 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	26.2	20.3	20.4	20.5	17.4	**104.8**
AER Preliminary Decision *	n/a	n/a	n/a	n/a	n/a	**27.3**
RRP	28.4	21.2	22.1	21.7	18.8	**112.2**

* AER Preliminary Decision includes its adjustment for real cost escalation

Table 5-26 provides a detailed breakdown of our Unmodelled Repex, compared with our actual expenditure in the 2011 to 2015 regulatory period and the forecasts in our Regulatory Proposal and the AER's Preliminary Decision.

Table 5-26: Breakdown of Unmodelled Repex ($M, Real 2015)

	2011-15 Actual	Regulatory Proposal	Preliminary Decision *	RRP
a. ZSS primary asset replacement	**8.2**	**10.4**	**7.3**	**10.1**
(i) Zone Substation Assets	4.3	6.5	1.8	6.4
(ii) Zone Substation Buildings	4.0	3.9	5.6	3.8
b. Non VBRC Safety Projects	**1.4**	**6.5**	**0.4**	**6.4**
(i) Intelligent Secure Substation Asset Management	**1.4**	**6.5**	**0.4**	**6.4**
c. Operational Technology		**38.0**		**41.4**
(i) OT Safety		**19.7**		**24.5**
- Service Mains Deterioration Field Works		4.3		4.2
- In Meter Capabilities		2.4		2.4
- Light Detection And Ranging Asset Management		6.9		6.8
- OT Security		6.2		6.1
- DNSP Intelligent Network Device		0.0		5.1
(ii) OT Reliability		**6.9**		**6.8**
- Distribution Fault Anticipation Data Collection and Analytics		4.0		3.9
- Fault Location Identification and Application Development		2.9		2.8

	2011-15 Actual	Regulatory Proposal	Preliminary Decision *	RRP
(iii) OT Other		**11.4**		**10.2**
- Dynamic Rating Monitoring Control Communication		2.3		2.2
- Test Harness		1.0		1.0
- Pilot New and Innovative Technologies		7.1		7.0
- Network Optimiser		0.6		0.0
- Analytics and Forecasting Toolset		0.5		0.0
d. Network Reliability	**24.1**	**36.4**	**12.0**	**35.8**
(i) Automatic Circuit Reclosers and Remote Control Gas Switches	12.3	9.7	6.9	9.5
(ii) Fuse Savers	0.4	1.7	0.3	1.7
(iii) Rogue Feeders	3.7	5.7	1.1	5.6
(iv) Clashing	0.7	4.1	0.3	4.0
(v) Animal Proofing	6.5	10.6	3.2	10.4
(vi) Communications Upgrade	0.4	4.5	0.2	4.5
e. Environment	**2.4**	**5.3**	**0.3**	**5.2**
f. Power Quality Maintained	**5.3**	**8.2**	**0.8**	**8.0**
g. Terminal Station Redevelopment HTS and RTS	**0.0**	**0.0**	**0.0**	**5.2**
Total Other Unmodelled	**45.5**	**104.7**	**27.3**	**112.2**

* AER Preliminary Decision includes its adjustment for real cost escalation

Table 5-21 provides references to the new or revised supporting documents that support each line item of this Unmodelled Repex.

These documents address the three main reasons that the AER gave in its Preliminary Decision for rejecting our forecast Unmodelled Repex. It considered that:

- Our forecast was not in line with historical trends and understood that we were wanting to replace assets. In fact, our proposed expenditure is more in line with our historical expenditure once a correction is made for expenditure omitted from our CA RIN for 2011-2013 due to our misinterpretation of the reporting requirements. Comparisons with historical expenditure must also consider that a significant proportion of this expenditure is addressing externalities and reducing safety risk for our customers in accordance with our ALARP obligation;
- Our Business Cases were not robust because they lacked sufficient cost-benefit and options analysis – we have addressed this in the revised business cases that we have submitted in this RRP; and
- There was a lack of top-down assessment to support our forecasts – as discussed above, we have provided new documents that provide this assessment.

We discuss each of these matters in turn.

Historical trend of Unmodelled Repex

The key reason that the AER gave in its Preliminary Decision for reducing our Unmodelled Repex forecast related to its assessment of our historical Umodelled Repex. The AER reduced our forecast Unmodelled Repex from $104.7 million to $27.3 million, which the AER believed reflected our historical expenditure. However, as shown in Table 5-15 above, our Unmodelled Repex for the 2011 to 2015 regulatory period was in fact $45.5 million, not $27.3 million. We have submitted the corrected CA RIN template with this RRP (RRP 5-30).

The AER's misinterpretation arose because we did not include Unmodelled Repex under the "Repex" tab of the CA RIN for years 2011 to 2014 and it relied only on our expenditure for 2015. We did not include the Unmodelled Repex for 2011 to 2014 because the expenditure relates to the creation of new assets, not the replacement of existing assets. We note that other DNSPs categorised this type of expenditure as Augmentation capex (Augex).

We have now updated our RIN template to include the Unmodelled Repex for 2011 to 2014 and have re-provided this to the AER with this RRP. We have chosen to retain this expenditure as Repex, and not to reclassify the expenditure as Augex, because it is designed to address reliability, safety, power quality and environmental requirements. This expenditure relates to maintaining the network (as opposed to augmenting the network) and we therefore consider that it should be properly categorised as Repex.

The AER's concern that we are seeking a 'sudden' increase in asset replacement is therefore misplaced and its Preliminary Decision is based on incorrect data that understates the actual Unmodelled Repex and a misunderstanding that this Repex is asset replacement.

Accounting for this correction, the increase in unmodelled Repex is still significant. As presented in section 5.5.4 for all Repex, it is also insightful to attribute components of the increase to our drivers, as follows:

- $20.4 million - to address deteriorating reliability, safety and network health; and close the gap between current performance and targets for next period:
  - $1.9 million in asset replacement (earth grids, NERs, etc. classified in Unmodelled Repex); and
  - $18.5 million in specific reliability projects to maintain reliability.
- $25.5 million - to reduce safety risk as per ALARP obligation, and address safety externalities:
  - $11.1 million to address increased security and access breach risk;
  - $8.0 million to reduce electric shocks to the public by 50 per cent, as per our ALARP obligation; and
  - $6.4 million for LiDAR to reduce bushfire and other risks.
- $10.7 million - to address other externalities:
  - $2.7 million to address power quality issues resulting from increased PV to be installed;
  - $2.8 million to address environmental externalities like urban encroachment on substations; and
  - $5.2 million to address terminal station redevelopment works initiated by AusNet Services.
- $10.2 million – for other drivers:
  - $3.2 million capex efficiency; and
  - $7.0 million piloting new technologies.

Business Cases for Unmodelled Repex

The AER commented in its Preliminary Decisions that:

> *If repex in the forecast period exceeds historical expenditure, we would expect that the distributor to sufficiently justify the increase. As noted above, we consider repex is likely to be relatively recurrent between periods, and that historical repex can be used as a good guide when assessing United Energy's forecast. There are almost no historical examples of expenditure of this type in United Energy's replacement programs that we could identify. It is unclear why the need to replace these assets has suddenly and significantly arisen in the forthcoming period.*
>
> *We accept there may be a need to replace a number of these assets. However, we are of the view that United Energy has not provided justification why it needs to spend significantly more repex on some of these*

categories in the forthcoming period. United Energy has not provided business cases with reasonable options analysis or sufficient cost-benefit analysis to justify the proposed repex, and there is a lack of top-down assessment.

We assessed a sample of United Energy's business cases, as we could not identify comprehensive information for all categories. We concluded these were not sufficient to support the proposed replacement expenditure. The business cases did not contain robust options analysis. For example, the project is assessed versus a do nothing option. The cost-benefit analysis also appears insufficient.[34]

As set out in Table 5-21, we have updated our business cases to support our Unmodelled Repex. These documents include a discussion of the options considered and present cost-benefit analysis for the options. We refer the AER to these documents for a detailed justification of each expenditure item under the Unmodelled Repex category.

Top-down assessment

The AER was concerned that the Unmodelled Repex forecast in our Regulatory Proposal was not supported by an adequate top-down assessment. As discussed above, we have addressed this by providing three new documents with this RRP – our *Network Reliability Assessment, Network Safety Assessment* and *Asset High Risk of Failure Assessment* (and associated model). These documents consolidate our assessment work in each area and confirm the prudency and efficiency of our Unmodelled Repex forecast.

Our top down assessment is also summarised in section 5.5.2.

5.5.8. Key Category 4 – Response on Victorian Bushfire Royal Commission (VBRC)

Table 5-27 details our VBRC Repex forecast for this RRP in response to the AER's Preliminary Decision and the forecast in our Regulatory Proposal.

Table 5-27: VBRC Repex 2016-20 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	15.4	20.2	17.7	11.2	10.2	74.8
AER Preliminary Decision *	n/a	n/a	n/a	n/a	n/a	34.8
RRP	9.5	10.3	13.4	10.2	9.9	53.3

* AER Preliminary Decision includes its adjustment for real cost escalation

Table 5-28 provides a breakdown of our VBRC Repex, compared with our actual expenditure in the 2011 to 2015 regulatory period and the forecasts in our Regulatory Proposal and the AER's Preliminary Decision.

Table 5-28: Breakdown of VBRC ($M, Real 2015)

	Regulatory Proposal	Preliminary Decision *	RRP
HV ABC	19.0	18.6	30.2
REFCL	20.9	0.0	7.5
Other	34.8	16.2	15.6
Total VBRC Projects	**74.8**	**34.8**	**53.3**

* AER Preliminary Decision includes its adjustment for real cost escalation

[34] AER, Preliminary Decision, Attachment 6, page 6-81.

The AER's Preliminary Decision accepted our proposed expenditure in relation to the VBRC, with the exception of our proposed Repex in relation to the installation of four REFCL devices and the replacement of SWER lines. The AER commented that:

> *United Energy's business cases and other supporting material it has provided does not properly evaluate the costs versus the benefits of the REFCL or SWER replacement programs.*[35]

We do not accept the AER's Preliminary Decision in relation to REFCL devices and are proposing an increase in our Repex for HV ABC.

HV ABC

The AER's Preliminary Decision included approval of $18.6 million for the early replacement of HV ABC.

During 2015, there has been a significant increase in the failure rates of HV ABC, and an increasing proportion of these failures have contributed to fire starts in HBRA. This deteriorating performance has resulted in an increase in the risk of bushfires and increased community concern about the safety of these assets and the need to replace them sooner than forecast in our Regulatory Proposal.

Our Regulatory Proposal was based on us replacing half of our HV ABC assets in the 2016 to 2020 regulatory period. Based on the increased failure rates, a higher proportion of failures resulting in fire starts, and heightened community concern (see attached media reports – RRP 5-20a), we are now proposing to replace all of our HV ABC assets in the 2016 to 2020 regulatory period. On 23 December 2015, ESV wrote to us confirming their support for us undertaking increased replacement of HVABC in the 2016 to 2020 period. This letter is provided as an attachment to this RRP.

As a result, we are proposing to increase our Repex on HV ABC to $30.2 million in the 2016 to 2020 regulatory period.

This is further explained and justified in our HV Aerial Bundled Cable Strategic Analysis Plan - UE PL 2053.

REFCL devices

Since submitting our Regulatory Proposal, we have undertaken a Bushfire Mitigation ALARP Risk Assessment, which is included with this RRP as document UE PR 2511. This assessment identified that the installation of two REFCLs will reduce our overall bushfire risk by 35 per cent at a cost commensurate with the value of the risk reduction.

We are required to submit a Bushfire Mitigation Plan to Energy Safe Victoria in accordance with the Electricity Safety Act 1998 (Vic). The Bushfire Mitigation Plan forms part of an accepted Electricity Safety Management Scheme (ESMS). It is a regulatory obligation to comply with the ESMS, and therefore the Bushfire Mitigation Plan.

In light of the AER's Preliminary Decision and our subsequent risk assessment, we have amended our Bushfire Mitigation Plan to include the installation of the two REFCL devises, as set out in our Regulatory Proposal. A copy of the updated Bushfire Mitigation Plan is submitted as an attachment to this RRP. We are seeking ESV approval as soon as practicable, and have therefore included the associated Repex in this RRP.

This is further explained and justified in our DMA and MTN ZSS Rapid Earth Fault Current Limiter (REFCL) Installation document

5.6. Non-network ICT capex

The AER accepted our base Non-Network IT and Communications capex of $102.1 million and transferred $1.5 million of forecast ACS ICT costs to SCS. However, the AER rejected our proposed IT capex of $61.54 million relating to RIN reporting and Power of Choice reforms. The AER reduced our proposed ICT capex allowance for 2016 to 2020 from $163.7 million to $103.6 million.

We do not accept the AER's rejection of our ICT capex for both RIN reporting and the Power of Choice reforms and expect to incur significant capex in the 2016 to 2020 regulatory period on these items. We have reflected this into

[35] AER, Preliminary Decision, Attachment 6, page 6-88.

our revised ICT capex forecast in Table 5-29, which compares this forecast to our Regulatory Proposal forecast and the AER's Preliminary Decision.

Table 5-29: Non-Network ICT capex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	30.7	44.9	37.0	21.7	29.3	163.7
AER Preliminary Decision	8.7	23.5	19.8	22.2	29.4	103.6
RRP	30.9	48.9	22.2	22.4	29.1	153.4

Table 5-30 provides a breakdown of the proposed capex for RIN reporting and Power of Choice reforms that we included in our Regulatory Proposal are now proposing in our RRP.

Table 5-30: Non-Network IT and Communications capex ($M, Real 2015)

	Rule change – reference to project justification	Regulatory Proposal	RRP
Proposed / Approved ICT capex (not relating to PoC and RIN Reporting)		**102.1**	**103.6**
Power of Choice	Consumer Data Access (PJ15 – POC)	4.5	2.5
	Customer Switching (PJ16 - POC)	2.8	1.2
	Demand Response Mechanism (PJ18 - POC)	1.8	1.8
	Metering Competition (PJ19 - POC)	8.3*	17.9
	Multiple Trading Relationships	8.7	0
	Network Pricing (PJ21 - POC)	2.8	2.8
	Demand Management AEMO Reporting (PJ25 - POC)	1.4	1.4
	Demand Management IT Platform (PJ26 - POC)	5.4	5.4
	Embedded Networks (PJ27 - POC)	1.5	0.8
RIN Reporting	Reporting (PJ22 - RIN)	24.3	16.3
Total		**163.7**	**153.4**

*The total proposed forecast included in the Regulatory Proposal was $16.5 million – however, 50 per cent was allocated to ACS.

We set out below our justification for our Power of Choice and RIN reporting ICT capex of $50.2 million included in this RRP.

5.6.1. Power of Choice ICT capex

In its Preliminary Decision the AER reject our proposed ICT capex for the Power of Choice reforms on the basis that:

> *We are not satisfied that United Energy's forecast ICT capex for Power of Choice related projects reasonably reflects the capex criteria. Given the uncertainty that exists around the nature of the applicable regulatory obligations, the possible system changes required, and the quantum of costs which may be incurred, we are*

not satisfied that United Energy's forecasts reasonably reflect the efficient costs of a prudent operator or a realistic expectation of the cost inputs required to achieve the capex objectives.[36] *Further, where a rule change process has commenced, or is expected to commence, but has not yet concluded, we do not consider that possible capex associated with a future rule change is required to meet an applicable regulatory obligation or requirement.*[37]

…

The scope, timing and cost of necessary IT system changes related to the various Power of Choice reforms remain uncertain. The regulatory change event pass through in the NER provides a mechanism for the recovery of costs associated with a regulatory change where those costs are material. We will review any updated or additional supporting information relating to these costs submitted by United Energy as part of its revised proposal."

Since submitting our Regulatory Proposal, significant advancement has been made on the Power of Choice Rule changes. Most of these Rules are now final and we have greater clarity about the detailed ICT capex required to meet them. We have therefore revised our forecast ICT costs and project justifications to reflect these changes.

Table 5-31 shows that we have reduced our forecast ICT requirements from $45.4 million to $33.5 million for Power of Choice and are proposing that all of this be recovered through SCS. This is largely due to the removal of ICT capex for Multiple Trading Relationships.

Table 5-31: Overview of Regulatory Proposal and RRP forecasts ($M, Real 2015)

Power of Choice Rule and project justification	Total Regulatory Proposal (2016-20)	RRP					
		2016	2017	2018	2019	2020	Total
Consumer Data Access (PJ15)	4.5	2.5	-	-	-	-	2.5
Customer Switching (PJ16)	2.8	-	1.2	-	-	-	1.2
Demand Response Mechanism (PJ18)	1.8	-	-	1.8	-	-	1.8
Metering Competition (PJ19)	8.3	3.3	14.6	-	-	-	17.9
Multiple Trading Relationships	8.7	-	-	-	-	-	-
Network Pricing (PJ21)	2.8	2.8	-	-	-	-	2.8
Demand Management AEMO Reporting (PJ25)	1.4	0.4	1.0	-	-	-	1.4
Demand Management IT Platform (PJ26)	5.4	2.4	3.0	-	-	-	5.4
Embedded Networks (PJ27)	1.5	-	0.8	-	-	-	0.8
TOTAL	**37.2**	**11.4**	**20.7**	**1.8**	-	-	**33.5**

We have applied the same approach to the allocation of costs between SCS and Metering ACS that the AER used in its Preliminary Decision. This approach provides that if an individual project cost is largely in one category then

[36] NER, 6.5.7(c).

[37] NER, 6.5.7(a)(2).

the total project cost is allocated to that category. On this basis, all Power of Choice project investment has been allocated to the SCS.

Table 5-32 overviews the status and scope of each of the Power of Choice Rules.

Table 5-32 shows that the AEMC has made final determinations of each of the Rules, other than for the Demand Response Mechanism.

Table 5-32: Power of Choice NER and Status

AEMC Rule / Advice	Status	Overview
Customer access to information about their electricity consumption	**Final determination** 6 November 2014.	Enables consumers to make better and informed choices about energy products and services by making it easier for them to get access to their electricity consumption information.
Electricity customer switching	**Final Report** 10 April 2014.	Improves the efficiency of customer switching through improved automation of the switching process enabling customers to transfer retailers on estimated readings.
Demand response mechanism – option for demand side resources to participate in the wholesale electricity market	**Consultation paper** 5 November 2015.	Provides capabilities to enable a demand side mechanism to be established whereby large consumers can sell demand into the NEM through an aggregator to facilitate efficient Demand Side Participation (DSP).
Expanding competition in metering and related services	**Final determination** 26 November 2015.	Establishes a competitive market for the supply, installation and operation of advanced metering with communications capability. It removes the restriction whereby DNSPs are responsible for metering residential customers and small business and will enable metering for this group of consumers to be provided by a competitive market.
Distribution network pricing arrangements	**Final determination** 27 November 2014	Enables DNSPs to set prices that reflect the cost of providing their services so that consumers can make informed choices about the way they use electricity.
Improving demand side participation information provided to AEMO by registered participants	**Final determination** 26 March 2015.	Provides AEMO information on contracted and price responsive demand side participation programs. This will allow AEMO to produce better load forecasts.
Reform of the demand management and embedded generation connection incentive scheme	**Final determination** 30 August 2015.	Enables the deployment of demand management as a cost effective alternative to traditional network investment.
Embedded networks	**Final determination** 17 December 2015.	Changes to the NER to: clarify metering and other arrangements for consumers in embedded networks; reduce the barriers to consumer access to competitive offers from market participants; and support competition in the provision of electricity and demand side services.
Multiple trading relationships	**Draft determination** 19 November 2015. Note: AEMC Draft Determination decided not to make a Draft rule and sought submissions by 14th January 2016.	Allows consumers to have more than one supplier of energy services. This includes enabling consumers to have more than one meter and each meter may be assigned to different Metering Coordinator (MC) and/or a different retailer.
Framework for open access and common communication standards for smart meters	**Final advice** 10 April 2014.	An open access and common communication standards framework provides a key component to establishing a competitive market for services enabled by smart metering technology.

AEMC Rule / Advice	Status	Overview
Implementation advice on the shared market protocol	**Final advice** 8 October 2015.	Provides a framework for access to advanced metering functionality to promote a market for services enabled by smart metering technology. This shared market protocol is expected to promote competition in services enabled by making it easier for retailers and service providers to access smart metering functions.

The requirements of these Rules impact many of our business processes and ICT systems. AEMO has published a Power of Choice Program Overview, which provides an indication of the workload, overlapping system developments and timeframes between 2015 and 2018. We have aligned our ICT investment proposal to be consistent with AEMO's Program Overview.

In preparing our ICT forecast for Power of Choice we have factored in other related rule changes (such as for Embedded Generation and Customer Switching) that support the Power of Choice program objectives. This will minimise the impact of changes on individual systems to achieve a prudent and efficient approach to the implementation of the ICT investment to give effect to the requirements of the Power of Choice rule changes.

Forecasting approach

Our approach to forecasting our ICT requirements aligns our initiatives with the NER's capex objectives and criteria. At a high level, this involves:

1. Understanding the Power of Choice rule changes based on the AEMC's and AEMO's documentation;
2. Identifying the processes, both automated and manual, that will be impacted by Power of Choice. This involves describing the process changes and detailing business requirements to operationalise the changes;
3. Identifying the new and any updated system functionality requirements required to support the process changes and business requirements. We determine whether a system (software / hardware) change is:
    - Mandatory – the existing system provides the wrong or insufficient data to that required by the rule change;
    - Essential – updating the system or installing a new system is more cost-effective than a manual solution;
    - "Nice to have" – the change delivers minimal benefit, but can be delivered at no or negligible cost; and
    - Not economic – the change can be provided cost-effectively by a manual process at a lower ongoing operational cost.
4. Grouping the process and system functionality requirements into project initiatives based on systems, timing, and resources required to implement the functionality in a cost effective manner;
5. Generating effort and cost estimates for the end-to-end implementation of the processes and system functionality to support Power of Choice. Every project, has been estimated using the same bottom-up approach and top-down review described in our Regulatory Proposal documents, which involved:
    - Bottom-up – evaluating resources (number and type) required throughout each phase of the project based on the project complexity and taking into account all known requirements. Hardware and Software requirements were also re-evaluated and estimated; and
    - Top-down – a "sanity check" review of the estimate for each project considering a range of factors, including:
        - Actual costs for similar recently completed projects;
        - Relationship, benefits and constraints associated with combining and/or separating projects to maximise the efficient use of resources including time, cost and quality; and
        - Experience of past projects including duration and resource requirements.

The project justification for each Power of Choice Rule change is based on the above approach. As noted above, we have updated our Power of Choice project justifications in this RRP. They:

- Describe the nature of the project;
- Describe how the project aligns with our business and ICT strategies;

- Set out options for addressing the requirement;
- Present the business benefit; and
- Present the proposed solution including the rationale for recommending this solution, approximate timing for delivery of the project and the forecast expenditure that will be incurred implementing the solution.

This matters ensure each project is aligned to the capex objectives and criteria in the NER.

Appendix E summarises our revised project justifications for the ICT expenditure to meet the Power of Choice Rule changes.

The projects include the Demand Management IT Platform. Although this project supports the implementation of Power of Choice, it is justified on the basis of providing lower cost non-network alternatives to traditional network augmentation. Other DNSPs have included similar capabilities in their ICT Network Management, Smarter Network and Customer Relationship Management (CRM) investments and these investments have been accepted by the AER in the Preliminary Decisions.

5.6.2. RIN reporting capex

Our Regulatory Proposal included $24.3 million of capex for RIN reporting to enable us to reliably report actual information, rather than estimated information. In its Preliminary Decision, the AER rejected our proposed RIN Reporting capex because it considered that:

- A significant driver of the project appears to be improving our asset management systems and data, rather than complying with the specific RIN reporting obligations;
- Further investment of the quantum proposed, so soon after replacing the same systems in the 2011–15 regulatory period, may reflect an inefficient approach to ICT investment; and
- The quantum of capex appears to reflect a risk averse assessment.

As such, the AER was not satisfied that the proposed scope and cost necessarily reflects our likely actual RIN compliance costs.

We have now revised our RIN reporting capex forecast to $16.3 million, as detailed in Table 5-33.

Table 5-33: RIN Reporting adjustment ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	8.1	16.2	0	0	0	24.3
AER Preliminary Determination	-	-	-	-	-	-
RRP	2.8	5.0	4.7	2.9	1.0	16.3

The key driver of our RIN reporting capex is the need to provide the AER with Actual Information, as opposed to Estimated Information. Currently, only one item of Repex information (transformer replacement capacity) is reported as Estimated Information, whereas about 340 items rely on the correct allocation of costs and other attributes, and accurate estimation to produce Actual Information. While our auditors have previously considered these items meet the RIN definition of Actual Information, the potential for misallocation or inaccuracies in the data is such that we may not be able to provide Actual Information in all future years.

Current data issues in the Category Analysis RIN template 2.2.1 include:

- Operating voltage is not recorded for poles, pole top structures, overhead conductors, underground cables, service lines, transformers, and switchgear
- Material type is not recorded for poles
- Number of phases is not recorded for overhead conductors and transformers

- Customer type and connection complexity is not recorded for service lines
- Ampere rating is not recorded for transformers
- Asset type is not recorded for public lighting
- Function is not recorded for SCADA, network control and protection systems.

Current data issues in Category Analysis RIN template 2.2.2 include:

- Feeder type is not recorded for poles, overhead conductors and underground cables; and
- Total MVA replaced and disposed is not recorded for transformers.

Currently, the RIN information for these items is prepared using related information (primarily work orders) to allocate the actual expenditures to volumes of assets installed, replaced and failed.

The current allocation process has meant diverting staff away from their business as usual activities. While this has been possible in past years by prioritising work, a continuation of this approach in the longer term is not sustainable as deferred activities must be undertaken. Additional opex of $1.5 million per annum would be required to retain the current allocation approach, with no guarantee that Actual Information could be provided in all years due to the lack of robustness inherent in this approach.

Meeting the AER's requirements for reliable RIN reporting of Actual Information will require us to make significant changes to our IT systems and business processes to capture and process additional data. In addition, new and modified work practices will be required. In summary, we will need to:

- Collect additional information to remove the estimated component of items of reported information;
- Change IT systems to accept the additional information;
- Establish new reports; and
- Revise certain business processes so that we can provide information that meets the RIN requirements.

We have revised our RIN reporting capex forecast in light of the AER's Preliminary Decision. We have reduced our forecast by:

- Retaining manual processes, allocating costs and other attributes, and estimating conductors and services until the IT changes are required for asset management purposes; and
- Only capturing data that is essential for RIN reporting, retaining some manual data manipulation and allocating costs and other attributes until 'business as usual' processes can provide the data directly.

Revised Justification paper PJ22 - RIN Reporting that we have provided as part of this RRP provides further detail about our RIN reporting capex proposal.

5.7. Non-Network General Other capex

We accept the AER's forecast in its Preliminary Decision for our Non-Network General Other capex of $30.9 million for 2016 to 2020.

Table 5-34: Non-Network Other capex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	14.0	4.0	3.5	4.3	5.1	30.9
AER Preliminary Decision	14.0	4.0	3.5	4.3	5.1	30.9
RRP	14.0	4.0	3.5	4.3	5.1	30.9

5.8. Cost escalation adjustment

We accept the AER's labour and material real cost escalation rates and have maintained the same weightings that we submitted in our Regulatory Proposal that the AER accepted.

We have reapplied the AER's real labour and material escalations and weightings to our revised capex forecasts.

6. Opex forecasts

Key messages:

- We accept the AER's adjusted base year allowance, subject to including a revised forecast of $12.38 million for metering opex and to adding back a reversal of $0.865 million for a licence fee paid to the Victorian Department of Treasury and Finance (DTF).
- We accept the AER's:
  - Application of its rate of change;
  - Output growth forecast, subject to applying our revised forecast of customer connections;
  - Real price growth forecast (being the average of DAE and BIS's forecasts), subject to changes in the weighting of labour and non-labour costs that we understand have been proposed to the AER by other Victorian DNSPs. If the AER accepts their proposals then they should also be applied to us, to the extent that it reflects more recent information; and
  - Productivity growth forecast of zero.
- We accept some aspects of the AER's Preliminary Decision on our step changes but do not accept others:
  - We accept the AER's approval of our proposed opex for pole top inspections, its treatment of our regulatory submission costs in the opex base year and we have withdrawn our Energy Safe Victoria safety obligations step change;
  - We do not accept the AER's Preliminary Decision on the following step changes and have re-included them in this RRP: Power of Choice; RIN reporting; 2015 Electricity Line Clearance Regulations (previously named Energy Safe Victoria rule changes); Council trees; stakeholder engagement; neutral testing; network planning and analytics; and IT security costs;
  - We remain committed to the following projects and programs but do not include them as step changes in this RRP: effortless customer experience program; customer charter; Guideline 11; and insurance premiums; and
  - Include new step changes (that were not included in our Regulatory Proposal) for costs related to new pricing obligations and the National Energy Customer Framework (NECF), which are driven by new regulatory obligations.
- We do not accept the AER's decision in relation to our opex allowance for GSLs and have updated our forecast based on the payment arrangements in the ESCV's draft decision on the Victorian GSL Payment Scheme.
- We accept the AER's debt raising cost percentage of 0.085 per cent, which translates to a debt raising cost of $5.8 million based on the application of the AER's PTRM.

6.1. AER's Preliminary Decision

In our Regulatory Proposal we proposed a total opex forecast for 2016 to 2020 of $800.4 million, or $780.2 million excluding Debt Raising Costs ($13.7 million) and the Demand Management Innovation Allowance ($6.6 million).

In its Preliminary Decision, the AER rejected our proposed opex forecast and substituted its own forecast of $653.9 million. This represented a reduction of $126.2 million or 16 per cent. Table 6-1 provides a breakdown of the reductions that the AER applied to our opex forecast (excluding Debt Raising Costs and the DMIA).

Table 6-1: AER's opex reductions 2016 to 2020 ($M, Real 2015)

	Regulatory Proposal	AER Preliminary Decision	AER Adjustment	% Reduction
Efficient adjusted base year	705.5	625.1	(80.4)	(11%)
Rate of change				
Real price growth	7.0	12.7	5.7	81%
Output growth	8.1	11.5	3.4	42%
Step changes	53.8	2.4	(51.4)	(96%)
Guaranteed Service Levels	5.7	2.2	(3.5)	(61%)
Total opex (excluding Debt Raising Costs and DMIA)	780.1	653.9	(126.2)	(16%)

Table 6-2 details the adjustments that the AER made in its Preliminary Decision to our proposed Debt Raising Costs and DMIA.

Table 6-2: AER's Debt Raising Costs and DMIA reductions 2016 to 2020 ($M, Real 2015)

	Regulatory Proposal	AER Preliminary Decision	AER Reduction	Share of total reduction
DMIA	6.6	2.0	(4.6)	36%
Debt Raising Costs	13.7	5.5	(8.2)	64%
Total Debt Raising Costs and DMIA	20.3	7.5	(12.8)	100%

6.2. Revised Opex forecast

Table 6-3 sets out our revised opex forecast for SCS for our 2016 to 2020 regulatory period. The remainder of this chapter explains and justifies each component of this forecast.

Table 6-3: Forecast opex – Standard Control Services ($M, Real 2015) *

	2016	2017	2018	2019	2020	Total
Adjusted Base Year	138.3	138.3	138.3	138.3	138.3	**691.6**
Output Growth	1.1	2.1	3.4	4.4	5.5	**16.6**
Price Growth	0.3	1.1	2.2	3.6	4.9	**12.2**
Productivity Growth	0.0	0.0	0.0	0.0	0.0	**0.0**
Step Changes	5.8	7.0	9.2	9.5	10.1	**41.6**
Guaranteed Service Levels	1.4	1.4	1.4	1.4	1.4	**7.0**
DMIS	2.4	1.3	1.1	1.1	0.8	**6.6**
Debt raising costs	1.0	1.1	1.2	1.2	1.2	**5.8**
Total	**150.3**	**152.3**	**157.0**	**159.5**	**162.2**	**781.4**

* Excludes shared assets and Efficiency Carryover Mechanism

6.3. Opex benchmarking

In our Regulatory Proposal, we explained that 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.

The AER's Preliminary Decision supports this view. In relation to its findings on its multilateral total factor productivity (MTFP) and multilateral partial factor productivity (MPFP) analysis, the AER stated that:

> *Economic Insights' MTFP and MPFP modelling indicates that United Energy is relatively efficient overall and also in the use of its opex.*[38]
>
> *The MTFP results indicate that United Energy is amongst the most productive service providers in the NEM.*[39]
>
> *Our view is that United Energy and the other Victorian service providers already appear relatively efficient when compared to the NSW and Queensland service providers.*[40]

In its findings on its analysis of partial performance indicators, the AER stated that:

> *United Energy appears to be one of the more efficient networks. As such, we consider that this benchmarking supports the findings of the econometric benchmarking…..*
>
> *Although a number of PPIs are presented in this report we consider that the most relevant PPIs are opex per customer and total cost per customer. This is because customer numbers appears to be the most material driver of costs for service providers. Figure A.4 and Figure A.5 present these PPIs. These figures show that United Energy (UED) incurs relatively low opex and total cost per customer when compared to its peers.*[41]

[38] AER, Preliminary Decision - United Energy distribution determination 2016 to 2020, Attachment 7 – Operating expenditure, October 2015, page 7-30

[39] AER, Preliminary Decision - United Energy distribution determination 2016 to 2020, Attachment 7 – Operating expenditure, October 2015, page 7-30

[40] AER, Preliminary Decision - United Energy distribution determination 2016 to 2020, Attachment 7 – Operating expenditure, October 2015, page 7-33

[41] AER, Preliminary Decision - United Energy distribution determination 2016 to 2020, Attachment 7 – Operating expenditure, October 2015, pages 7-34 to 7-35

In its findings on the trend in our opex, the AER stated that:

> *Benchmarking across the 2006–13 period indicates that United Energy performs relatively well against its peers.*[42]

The analysis in the AER's Preliminary Decision is supported by the AER's November 2015 Annual Benchmarking Report (Distribution) that shows that we are:

- The second most efficient DNSP in 2013-14 and the third most efficient DNSP over the 2006–14 period, when assessed on the basis of multilateral total factor productivity (MTFP) analysis;
- One of the top performers on the opex and the capital multilateral partial factor productivity (MPFP) analysis;
- The DNSP with the lowest total user cost per customer.

6.4. Efficient base year inclusive of adjustments

Table 6-4 details our opex forecast for this RRP and compares it to our Regulatory Proposal and the AER's Preliminary Decision. We consider that our revised forecast of the base year better meets the requirements of the clause 6.5.6 of the NER for the reasons set out below.

Table 6-4: Efficient Base Year Opex 2016 to 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	141.1	141.1	141.1	141.1	141.1	705.5
AER Preliminary Decision	125.0	125.0	125.0	125.0	125.0	625.1
RRP	138.3	138.3	138.3	138.3	138.3	691.6

The AER's Preliminary Decision made the adjustments detailed in Table 6-5 to the base year forecast in our Regulatory Proposal.

Table 6-5: AER base year adjustments ($M)

Nature of adjustment	Preliminary Decision	RRP	UE Comments
Total opex 2014 (Real 2014)	121.87	122.73	Add back licence fee of $0.865 million
Remove debt raising costs (Real 2014)	-	-	Agree with AER
Remove movement in provisions (Real 2014)	- 0.76	- 0.76	Agree with AER
Remove DMIA expenditure (Real 2014)	- 0.66	- 0.66	Agree with AER
Remove GSL payments (Real 2014)	- 1.12	- 1.12	Agree with AER
Remove scrapping of assets (Real 2014)	-		Agree with AER
Total (Real 2014)	**119.32**	**120.19**	Agree with AER
Convert to 2015 @ 103.38% (Real 2015)	123.35	124.24	Using AER CPI

[42] AER, Preliminary Decision - United Energy distribution determination 2016 to 2020, Attachment 7 – Operating expenditure, October 2015, pages 7-36

Nature of adjustment	Preliminary Decision	RRP	UE Comments
Diff between 2014 and 2015 allowance (Real 2015)	1.67	1.67	Agree with AER
AMI Transfer (Real 2015)	-	12.38	Required AMI transfer – refer
Efficient base year (Real 2015)	**125.02**	**138.30**	

We accept the AER's adjusted base year with two exceptions:

- We do not accept the AER removing $18.9 million from the opex base year in relation to AMI, as this is required to provide our SCS; and
- We consider that $0.865 million should be added back to the 2014 base year for a reversal of a licence fee that was paid to the Victorian DTF in 2008. A corresponding adjustment should be made to the Efficiency Carryover Mechanism.

We explain each of these matters further below.

6.4.1. Metering Opex

Section 13.2.2 sets out our proposal to allocate $12.38 million from metering opex to SCS opex in the 2016 to 2020 regulatory period. This section also addresses the concerns that the AER raised in its Preliminary Decision about our proposed transfer.

6.4.2. Adjustment for reversal of licence fee

Our 2014 base year opex included a reversal of $0.865 million relating to our licence fee payable to the Victorian DTF. This was a reversal of accruals made during the 2006 to 2010 period, which were only reversed out in 2014. The delay in timing was due to an accounting error. The original amount was previously adjusted for by the AER in the 2011 to 2015 final decision. The $0.865 million item was included in tab 12a. Operating A of our Annual RIN.

The costs relating to the licence fee are recovered via a separate part of the tariff formula and should not be included in the base year costs. As a consequence, the $0.865 million reversal should be added back into the base year.

We have reflected the $0.865 million adjustment into the Efficiency Carryover Mechanism so that there is no net effect on our future revenue. This is discussed in section 10.1.3 of this RRP and in a confidential letter dated 2 December 2015 from UE to the AER.

Despite this not impacting our future revenue, the AER should make the $0.865 million adjustment to the base year in order to establish the correct base year that can be used for all future regulatory purposes.

6.5. Rate of change

In our Regulatory Proposal, we proposed an allowance of $15.1 million for rate of change. In its Preliminary Decision, the AER applied a substitute forecast of $24.0 million.

The AER made the following decisions on the three rate of change components:

- Real price growth – The AER rejected our labour price growth forecast by BIS Shrapnel and substituted it with a forecast based on an average forecasts from Deloitte Access Economics and BIS Shrapnel. This reduced our real price growth forecast by around 0.32 per cent per annum
- Output growth – The AER accepted the parameters that we proposed (which were based on those used by the AER in its NSW and ACT determinations), albeit that it used AEMO's, rather than our own, maximum demand forecasts to calculate ratcheted maximum demand. The AER used our customer numbers and circuit length forecasts set out in our Reset RIN. This reduced our output growth forecast by around 0.44 per cent per annum

- Productivity growth – The AER applied zero productivity growth, consistent with our Regulatory Proposal.

The AER revised the way in which we applied the rate of change formula from what we proposed in our Regulatory Proposal.

6.5.1. Rate of change formula

We accept the application of the rate of change formula that the AER proposed in its Preliminary Decision. This approach is consistent with what the AER has applied in its recent Determinations for other DNSPs. This results in a $9 million increase in our rate of change allowance.

6.5.2. Output growth

We accept the AER using the output change measures and respective weightings that we set out in our Regulatory Proposal, which were based on the AER Draft Distribution Determination for the NSW and ACT DNSPs'[43] being:

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

Table 6-6 details our output growth forecast for this RRP and compares it to our Regulatory Proposal and the AER's Preliminary Decision.

Table 6-6: Output Growth Opex 2016 to 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	1.2	1.5	2.1	1.7	1.6	8.1
AER Preliminary Decision	1.0	1.8	2.8	3.6	4.5	13.7
RRP	1.1	2.1	3.4	4.4	5.5	16.6

6.5.3. Real price growth

We accept the AER basing the real price growth forecast on an average of DAE and BIS Shrapnel's forecast.

We also accept the AER's 62/38 per cent split of labour and non-labour costs, consistent with our Regulatory Proposal. However, we understand that other Victorian DNSPs have undertaken work to determine the split of labour and non-labour costs based on actual data. If the AER accepts this for the other Victorian DNSPs then it should also be applied to us, to the extent that it reflects more recent information.

Table 6-7 details our output growth forecast for this RRP and compares it to our proposal in our Regulatory Proposal and the AER's Preliminary Decision.

[43] These output measures and weightings were derived by Economic Insights (EI)

Table 6-7: Real Price Growth Opex 2016 to 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	0.8	1.1	1.6	1.9	1.6	7.0
AER Preliminary Decision	0.3	0.9	1.9	3.1	4.2	10.3
RRP	0.3	1.1	2.2	3.6	4.9	12.2

6.5.4. Productivity growth

We accept the AER's Preliminary Decision to apply a zero productivity growth allowance. This is consistent with our Regulatory Proposal. Our forecast therefore remains unchanged at zero, as detailed in Table 6-8.

Table 6-8: Productivity Growth Opex 2016 to 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	-	-	-	-	-	-
AER Preliminary Decision	-	-	-	-	-	-
RRP	-	-	-	-	-	-

6.5.5. Total rate of change

On the basis of the above three components, our revised proposed total rate of change forecast is $28.8 million, as detailed in Table 6-9 below.

Table 6-9: Total Rate of Change Opex 2016 to 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	2.0	2.6	3.7	3.6	3.2	15.1
AER Preliminary Decision	1.2	2.7	4.7	6.7	8.6	24.0
RRP	1.4	3.2	5.6	8.1	10.4	28.8

6.6. Step change

Our Regulatory Proposal included step changes totalling $53.8 million for the 2016 to 2020 regulatory period.

In its Preliminary Decision, the AER rejected all of our step changes except for pole top inspections of $2.4 million. This is shown in Table 6-10 below.

Table 6-10: 2016 to 2020 step changes ($M, Real 2015)

	Regulatory Proposal	AER Preliminary Decision	AER Reduction
Step changes	53.8	2.4	(51.4)

We have reviewed and amended our proposed step changes in light of the AER's Preliminary Decision as well as changes in our circumstances since we submitted our Regulatory Proposal. As discussed further below, we:

- Accept the AER's Preliminary Decision on the following step changes:
  - The approval of our proposed opex for pole top inspections;
  - The treatment of our regulatory submission costs in the opex base year; and
  - Energy Safe Victoria safety obligations – we have withdrawn this because it can be funded through the recurrent base year allowance.
- Do not accept the AER's Preliminary Decision on the following step changes and have included them in this RRP:
  - Power of Choice – although we have withdrawn:
    - "1c. Power of Choice – Embedded Network" because it can be funded through the recurrent base year allowance; and
    - "1e. Power of Choice – Network" as this is now recovered (in a modified form) by "13. NECF".
  - RIN reporting;
  - Energy Safety Victoria rule changes, which we have renamed "2015 Electricity Line Clearance Regulations";
  - Stakeholder engagement;
  - Neutral testing – we do not accept the AER's view presented on page 7-71 of Attachment 7 of its Preliminary Decision that our neutral testing costs are included in our base year;
  - Network planning and analytics; and
  - IT security costs.
- Remain committed to the following projects and programs but we have not included them as step changes in this RRP:
  - Effortless Customer Experience Program – we have withdrawn this because it can be funded through efficiency savings;
  - Customer charter – we have withdrawn this because it can be funded through the recurrent base year allowance;
  - Council trees – we have withdrawn this because it is has been superseded by our revised step change for 2015 Electricity Line Clearance Regulations;
  - Guideline 11 – we have withdrawn this because we accept that there has not been a change in regulatory obligations; and
  - Insurance premiums – we have withdrawn this because it can be funded through the recurrent base year allowance.
- Have included the following new step changes for costs driven by new regulatory obligations:
  - New pricing obligations; and
  - NECF.

Our revised list of step changes and the associated costs included in our RRP are set out in Table 6-11.

Table 6-11: 2016 to 2020 step changes ($M, Real 2015)

New regulatory obligations – annual			Regulatory Proposal	AER Preliminary Decision	Revised Proposal
1.	a.	Power of Choice – Metering Competition	3.5	-	4.9
	b.	Power of Choice – Customer Access to Data	1.7	-	1.8
	c.	Power of Choice – Embedded Network	0.7	-	Withdrawn
	d.	Power of Choice – Demand Management IT Platform	1.6	-	1.6
	e.	Power of Choice – Network (Chapter 5 and Chapter 5A – Embedded Generation Connection, including Solar)	3.5	-	Withdrawn
2.		Regulatory Information Notice reporting	1.6	-	4.6
3.	a.	Energy Safe Victoria safety obligations	1.0	-	Withdrawn
	b.	2015 Electricity Line Clearance Regulations (previously named Energy Safe Victoria rule changes)	8.7	-	11.7
4.	a.	Effortless Customer Experience Program	6.0	-	Withdrawn
	b.	Stakeholder engagement	1.3	-	1.3
	c.	Council trees	3.0	-	Merged with 3b
5.		Customer charter	0.7	-	Withdrawn
6.		Regulatory submission cost	2.3	-	Withdrawn
7.	a.	Neutral Testing	0.4	-	2.3
	b.	Network Planning and Analytics - IT Capital Program	4.1	-	4.1
8.		Guideline 11 EWOV Direction	4.5	-	Withdrawn
9.		IT security costs	4.0	-	3.9
10.		Insurance premiums	2.3	-	Withdrawn
11.		Pole top inspection	2.4	2.4	2.4
12.	New	New pricing obligations		n.a.	2.5
13	New	NECF		n.a.	0.7
		Real price escalations	0.5		-
		Total	**53.8**	**2.4**	**41.6**

Our justification for each of these step changes is provided in Appendix F of this RRP.

6.7. Guaranteed Service Levels

In our Regulatory Proposal, we forecast GSLs for 2016 to 2020 based on our 2014 base year GSL payments of $1.15 million. The AER rejected this and substituted it with a forecast of $0.44 million, based on the average of our GSL payments for the five year period 2010 and 2014.

We maintain our view that our GSL forecast should be based on our 2014 actual expenditure. Taking a base year approach is consistent with the AER's preferred forecasting methodology and how we have forecast most of the rest of our Opex. The AER has not explained why it thinks it appropriate to forecast GSL expenditure differently to our other Opex.

We propose adjusting our GSL forecast for changes that the ESC has made to the GSL scheme under the Electricity Distribution Code. These changes relate to:

- Increases in the payments for certain GSLs;
- More onerous thresholds for certain GSLs; and
- A new GSL relating to the duration of an individual interruption.

Table 6-12 our revised GSL forecast.

Table 6-12: Increases arising from ($'000s, Real 2015)

	Forecast
2014 Base Year GSL Opex	1,123.9
Increases for changes to GSL scheme:	
– New Connections 1-4 day delay	8.0
– New Connections - 5+ day delay	4.0
– Annual Duration of Unplanned Interruptions - 20 hours	7.0
– Annual Duration of Unplanned Interruptions - 30 hours	103.0
– Annual Duration of Unplanned Interruptions - 60 hours	108.0
– Low reliability payments - 10 events (>8 events)	8.0
– Low reliability payments - 15 events (>12 event)	28.0
– Low reliability payments - 30 events (>24 event)	22.0
– Annual Frequency of Momentary Interruptions - 24	-
– Annual Frequency of Momentary Interruptions - 36	-
– Street lights not repaired in 2 days	-
– New Connections 1-4 day delay	1.0
Total Scheme Changes	**289.0**
Revised Total GSL Opex per annum	**1,412.9**

Table 6-13 details our revised five year GSL forecast relative to our Regulatory Proposal and the AER's Preliminary Decision.

Table 6-13: GSL Opex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	1.2	1.2	1.2	1.2	1.2	5.8
AER Preliminary Decision	0.4	0.4	0.4	0.4	0.4	2.2
RRP	1.4	1.4	1.4	1.4	1.4	7.0

6.8. Demand Management Innovation Allowance

We do not accept the AER's forecast in its Preliminary Decision for our DMIA opex of $2.0 million for 2016 to 2020.

We consider our original forecast of $6.6 million is necessary to properly investigate and explore efficient non-network alternatives including to manage expected demand for SCS in the 2016 to 2020 period. We set out the investment initiatives that we propose undertaking in our "Demand Management & DMIS Strategy & Plan 2016-2020" submitted with our Regulatory Proposal.

The AER's Preliminary Decision is based on a scheme published in 2009 that has not been updated to recognise the importance of providing an appropriate allowance to enable us to explore innovation opportunities associated with new technology and techniques that will assist us identify ways of supplying our customers at a lower cost over long term. Many of our stakeholders have expressed strong views that the AER's Preliminary Decision is not sufficient to drive the necessary change in the delivery of electricity services.

While we support the requirements of the AEMC's recently published (20 August 2015) Final Rule Determination on National Electricity Amendment (Demand Management Incentive Scheme), which include requiring the AER to develop and publish new guidelines by 1 December 2016, these guidelines will not apply to us until 2021. We consider this results in a significant lost opportunity to ensure that we are appropriately compensated to explore innovation opportunities associated with new technology and techniques during the 2016 to 2020 period. We consider that delaying change in this critical area is detrimental to ensuring investment is innovative and is driving the lowest possible prices.

We encourage the AER to review the incentive arrangement for non-network alternatives in the UK under the RIIO (Revenue = Incentives + Innovation + Outputs) regulatory framework. The RIIO provides significant financial incentives DNSPs to drive new and innovative investment that meets both the carbon challenge and ensures lower prices to customers over the long term.

Table 6-14 details our five year DMIA forecast, which is unchanged from our Regulatory Proposal, relative to the AER's Preliminary Decision.

Table 6-14: DMIA Opex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	2.4	1.3	1.1	1.1	0.8	6.6
AER Preliminary Decision	0.4	0.4	0.4	0.4	0.4	2.0
RRP	2.4	1.3	1.1	1.1	0.8	6.6

6.9. Debt raising costs

We accept the AER's debt raising cost percentage of 0.085 per cent, which translates to a debt raising cost of $5.8 million based on the application of the AER's PTRM.

Table 6-15: Debt Raising Costs Opex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	2.5	2.6	2.7	2.9	3.0	13.7
AER Preliminary Decision	1.0	1.1	1.1	1.1	1.2	5.5
RRP	1.0	1.1	1.2	1.2	1.2	5.8

7. Regulatory Asset Base and Depreciation

Key messages:

- We have prepared our revised depreciation forecast based on the methodology applied by the AER in its Final Determination for SA Power Networks (SAPN) and our revised forecast asset additions. This results in a revised depreciation forecast (excluding inflation indexation on the opening Regulatory Asset Base (RAB)) of $463.3 million compared with $388.2 million in our Regulatory Proposal.
- We have adopted a value of $2,063.7 million (nominal) as our revised opening RAB as at 1 January 2016. The roll forward of the RAB has been calculated in accordance with clauses S6.2.1(e) and S6.2.3 of the NER, using the AER's RFM.
- Depreciation from 2011 to 2015 is based on the AER's Distribution Determination for the 2011 to 2015 regulatory period applying actual depreciation calculated using the lives defined in the AER's PTRM.

7.1. Depreciation

We do not accept the AER's Preliminary Decision on our depreciation forecast and have developed a revised forecast using the methodology approved by the AER in its 2015-2019 Final Determination for SAPN. The AER has labelled this methodology the "year-by-year tracking approach"[44]. Table 7-1 details our revised five year depreciation forecast, as well as our forecast in our Regulatory Proposal and the AER's forecast in its Preliminary Decision. We have applied a 2.01 per cent CPI in our RRP, whereas a 2.5 per cent CPI was used in our Regulatory Proposal and the AER's Preliminary Decision. This results in an increase in regulatory depreciation, which is more than offset by a decrease in inflation on the opening RAB.

Table 7-1: Depreciation excluding inflation indexation on opening RAB ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal (applying 2.5% CPI)	69.6	80.8	88.3	72.5	77.0	388.2
AER Preliminary Decision (applying 2.5% CPI)	54.4	60.6	68.9	68.7	62.8	315.4
RRP (applying 2.01% CPI)	79.8	81.2	93.3	102.1	106.9	463.3

In accordance clause 6.5.5 of the NER, we have continued to apply the straight-line depreciation method employed in the AER's PTRM to forecast depreciation. We have also not made any changes to the asset classes or standard asset lives from those set out in our Regulatory Proposal.

We have, however, revised our approach to determining the remaining asset lives in each asset class. Our revised approach is based on the AER's "year-by-year tracking approach" (which was referred to by SAPN and its consultants HoustonKemp as the "baseline approach"). Under this approach:

- Assets in existence at 1 January 2011 are depreciated by asset class using straight-line depreciation with the useful lives determined in the 2010 final decision;
- Capex in each year of the 2011 to 2015 period is grouped by asset type and separately depreciated over their standard lives.

Under the "year-by-year tracking approach", there is no grouping of pre and post-2011 assets in the same asset class. This addresses any distortion of remaining asset lives that would otherwise arise from combining pre and post-2011 assets in the same class.

[44] AER Final Decision SA Power Networks 2015-16 to 2019-20, Attachment 5 – Regulatory depreciation, p. 5-8. Found at: "year-by-year tracking approach"http://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20SA%20Power%20Networks%20distribution%20determination%20-%20Attachment%205%20-%20%20Regulatory%20depreciation%20-%20October%202015.pdf

Table 7-2 details for each asset class the standard lives and the remaining lives as at 1 January 2016 that we:

- Proposed in our Regulatory Proposal; and
- Are now proposing in our RRP.

Table 7-2: Asset lives

Asset	Standard lives	Regulatory Proposal	RRP	
		Remaining life for 2016 opening RAB as at 1 January 2016	Remaining life for 2011 opening RAB as at 1 January 2016	Remaining life for 2011-2015 Capex
Sub – transmission	60.0	26.6	19.0	56-60
Distribution system	35.6	25.0	19.0	31.6 - 35.6
Standard metering	n/a	1.0	0.0	n/a
Public lighting	n/a	1.0	0.0	n/a
SCADA (5 Year –Asset)	5.0	2.1	0.0	1-5
Non-Network ICT	5.0	3.2	0.0	1-5
Non- Network - Other	7.5	2.5	0.0	3.5-7.5
Neutral screen services	n/a	0.1	0.0	n/a
Overloaded transformers	n/a	0.1	0.0	n/a
SCADA (10 Year –Asset)	10.0	5.0	0.0	6-10
Land	n/a	n/a	0.0	n/a

7.2. Opening RAB as at 1 January 2016

We are required to establish an opening value for the RAB as at 1 January 2016, which is the starting date for the 2016 to 2020 regulatory period. In accordance with the NER, we have applied the AER's RFM and PTRM to calculate this value. Table 7-3 provides a reconciliation of our 1 January 2016 RAB with the AER's estimate in its Distribution Determination for the 2011 to 2015 regulatory period. In accordance with the requirements of clause S6.2.1(e)(4) of the NER, the value of the RAB only includes capex that is properly allocated to the provision of SCS in accordance with our Cost Allocation Method.

Table 7-3: Reconciliation of opening asset base as at 1 January 2016 to AER's Distribution Determination ($M, Nominal)

	Regulatory Proposal	Preliminary Decision	RRP
2015 interim closing	2,050.2	2,033.4	2,045.2
2010 CPI adjustment	19.1	18.5	18.5
2016 opening RAB	2,069.3	2,051.9	2,063.7

The AER made a number of adjustments to the opening RAB that we included in our Regulatory Proposal. We address each of the AER's adjustments in turn below.

7.2.1. Correcting the indexation of the 2010 RAB

In our Regulatory Proposal, we included an adjustment of $19.1 million to correct for an amount not included in the calculation of the 2011 Opening RAB in the AER's Distribution Determination for the 2011 to 2016 regulatory period.

In its Preliminary Decision, the AER accepted the need for this adjustment but calculated the amount to be $18.5 million, which it added to the closing RAB as at 31 December 2015.

We accept the AER's Preliminary Decision to apply a RAB adjustment of $18.5 million.

7.2.2. Inflation on Opening RAB

We accept the AER's proposed CPI index, however we do not accept the application of CPI for the purpose of calculating inflation on the Opening RAB. The AER adopts a lagged approach to calculating the CPI index, however it applies a CPI rate in advance when calculating inflation on the Opening RAB. Table 7-4 summarises the CPI index and CPI rate that we and the AER have used.

Table 7-4: Comparison of AER and UE inflation rates

		2010	2011	2012	2013	2014	2015
AER (“Actual approach”)	Actual CPI rate	2.79%	3.52%	2.00%	2.16%	2.31%	2.31%
	Actual CPI	1.0000	1.0279	1.0640	1.0854	1.1088	1.1344
UE (“Lagged approach”)	Actual CPI rate	1.26%	2.79%	3.52%	2.00%	2.16%	2.31%
	Actual CPI	1.0000	1.0279	1.0640	1.0854	1.1088	1.1344

We note that the AER has adopted a different methodology for CPI inflation on the Opening RAB to that applied in the AER's 2010 Final Decision. In the 2010 RFM, the AER applied the CPI each January that was published in the previous September. This is demonstrated in Table 7-5 below.

Table 7-5: CPI applied by AER to Opening RAB

CPI Publish Date	Sep-05	Sep-06	Sep-07	Sep-08	Sep-09	Sep-10
Published CPI	3.03%	3.94%	1.86%	4.98%	1.26%	2.79%
AER Applied to Opening RAB	Jan-06	Jan-07	Jan-08	Jan-09	Jan-10	Jan-11

Table 7-6 shows that CPI of 2.79 per cent published in September 2010 should have been applied to the January 2011 Opening RAB. Under the AER's revised approach, September 2010 CPI should be applied to the 2010 Opening RAB. This adjustment has not been included in our 2016 Opening RAB.

Table 7-6 demonstrates that our approach is consistent with that applied by the AER in its 2010 Final Decision.

Table 7-6: Comparison of AER and UE application of CPI to Opening RAB

CPI Publish Date	Sep-09	Sep-10	Sep-11	Sep-12	Sep-13	Sep-14	Sep-15
CPI Rate	1.26%	2.79%	3.52%	2.00%	2.16%	2.31%	1.50%
AER Application to Opening RAB	Jan-09	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15
UE Application to Opening RAB	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16

If the AER does not accept our methodology then we request an additional CPI adjustment to the 2010 Opening RAB of $44 million to reflect the omitted September 2010 CPI of 2.79 per cent. This is necessary to ensure that the AER satisfies both the National Electricity Objective (NEO) and the Revenue and Pricing Principles in the NEL.

7.2.3. Correcting the asset class allocation of actual gross capex from 2011 to 2014

The AER amended our proposed RFM for certain errors identified in the asset class allocation of the proposed actual gross capex from 2011 to 2014.

We accept the AER's amendments for this matter.

7.2.4. Adjusting allowed equity raising costs to the correct dollar terms

We accept the AER's revised equity raising costs of $3.5 million (Nominal) in 2011.

7.2.5. Adjusting the proposed capex for the movement in capitalised provisions.

We accept the AER's view that the movement in capitalised provisions during the regulatory period should be adjusted from capex inputs to the RFM.

7.3. RAB for the 2016 to 2020 regulatory period

Table 7-7 below presents a summary of the amounts, values and inputs we used to derive our forecast RAB value for each year of the 2016 to 2020 regulatory period. In accordance with the NER45, only actual and estimated capex attributable to the provision of SCS in accordance with our cost allocation methodology has been included in the RAB.

The assumptions adopted in rolling forward the RAB in the 2016 to 2020 regulatory period are:

- Forecast capex is consistent with the categories and amounts presented in this RRP;
- Depreciation has been calculated on a straight-line basis, as discussed in section 7.1, and in accordance with the requirements of clause 6.5.5(a) of the NER; and
- Asset disposals are forecast to be zero.

The forecast RAB for each year of the 2016 to 2020 regulatory period is shown in Table 7-7.

[45] S6.2.1(e)(4)

Table 7-7: RAB for 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020
Opening RAB	2,063.7	2,189.9	2,309.9	2,390.9	2,448.9
Plus capex (*includes equity raising costs)	256.9*	261.2	237.5	223.5	213.2
Plus Funding Costs	7.7	7.5	6.5	5.9	5.3
Less customer contributions	(19.2)	(27.4)	(29.5)	(29.8)	(30.2)
Less regulatory depreciation	(118.9)	(121.1)	(133.4)	(141.4)	(145.0)
Less disposals	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Closing RAB	**2,189.9**	**2,309.9**	**2,390.9**	**2,448.9**	**2,492.1**

Note: The values contained in this table have been calculated as per the requirements of the PTRM.

8. Rate of return, inflation and debt and equity raising costs

Key messages:

- Critical to the promotion of efficient investment is that businesses be provided with a reasonable opportunity to recover efficient costs (i.e. the costs that would be incurred by an efficient business in a workably competitive market).
- For the 2016 to 2020 regulatory period, we propose a rate of return of 8.70 per cent per annum based on a proposed return on debt of 7.80 per cent, a proposed return on equity of 10.05 per cent and a proposed gearing of 60 per cent.
- The estimation method that we propose for gamma reflects the value which equity-holders place on imputation credits. We propose to use an observed distribution rate (0.7), which is consistent with the AER's Rate of Return Guideline, (the Guideline), and previous findings of the Australian Competition Tribunal (the Tribunal)[46]. We propose that the distribution rate be combined with the best estimate of theta from market value studies (0.35), which leads to an estimate for gamma of 0.25.
- We propose to use the CEG implementation of the Fisher equation method to estimate inflation, which places 60 per cent weight on a 5-year inflation forecast and 40 per cent weight on a 10-year forecast. We also adopt CEG's recommendation to substitute actual inflation into the 5-year forecast used for indexation of the debt-financed portion of the RAB, where actual observations are available. We therefore propose to apply an inflation forecast of 2.01 per cent, based on an application of the Fisher equation method over the 20 business days to 30 September 2015.
- Once the Tribunal has published its decision for merits review of the AER's distribution determinations for the NSW and ACT electricity DNSPs and the NSW gas distributor, we will review the decision and consider the implications, if any, of that decision for the determination the AER is required to make for us.
- In accordance with the requirements set out in the AER's Rate of Return Guideline, we have nominated debt averaging periods for the last four years of the 2016 to 2020 regulatory period.

This chapter addresses the allowed rate of return, the value of imputation credits (gamma) and the method for forecasting inflation. These topics are addressed together in this chapter because they each impact on the overall return to investors. Specifically:

- Under the NER, the allowed rate of return is the post-tax return allowed to investors, calculated as a weighted average of the return on equity and return on debt;
- Gamma represents the value of imputation credits to investors associated with the payment of company tax. This value effectively forms part of the overall return to equity investors; and
- Forecast inflation is used to adjust the cash flows to maintain a real rate of return framework. If inflation is not correctly forecasted, the adjustment to cash flows may be too large (or too small) and thus investors may receive an overall return that is too low (or too high).

The rationale of economic regulation of network assets is to, insofar as possible, mimic the operation of, and replicate the outcomes in, a workably competitive market.

In order to promote the NEO, the overall return to investors must be sufficient to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. Critical to the promotion of efficient investment is that businesses be provided with a reasonable opportunity to recover efficient costs (i.e. the costs that would be incurred by an efficient business in a workably competitive market). This means that:

- The return on debt allowance must be such as to provide a reasonable opportunity to recover at least the efficient debt financing costs of a benchmark efficient entity (BEE) with a similar degree of risk as that which applies to us in respect of the provision of SCS;

[46] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [22].

- The return on equity allowance must reflect returns required by equity investors to invest in businesses facing a similar degree of risk;
- Gamma must reflect the value that equity-holders place on imputation credits (not simply their face value or utilisation rate). If the value of imputation credits is over-estimated, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers; and
- The inflation forecast must reflect market expectations of inflation over the regulatory period.

The Preliminary Decision does not provide for an overall return that is consistent with the NEO. For reasons set out in this chapter:

- The allowed rate of return is not commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to us in respect of the provision of standard control services;
- The value of imputation credits is over-estimated, meaning that the reduction to the overall return to account for imputation credits is too large; and
- The AER's forecast of inflation is also over-estimated, meaning that the reduction to the overall return to account for expected indexation of the regulatory asset base is to large and otherwise does not reflect current market expectations.

8.1. Achieving the allowed rate of return objective

The allowed rate of return objective (ARORO) is the touchstone for estimating the allowed rate of return. The NER require that:

- The return on equity for a regulatory period be estimated such that it contributes to the achievement of the ARORO; and
- The return on debt for a regulatory year be estimated such that it contributes to the achievement of the ARORO.

The ARORO is that the rate of return for a DNSP is to be commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to the DNSP in respect of the provision of standard control services.

As can be seen, the ARORO has two key elements:

- First, the ARORO requires identification of the level of risk that applies to the DNSP in respect of the provision of standard control services; and
- Secondly, the ARORO requires estimation of efficient financing costs for a BEE facing a similar degree of risk.

We consider that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia. Therefore, in constructing comparator datasets for the purposes of estimating a rate of return that is commensurate with efficient financing costs of a BEE, these datasets should include entities that face a similar degree of risk to that faced in the provision of electricity distribution services. That is, they should not be restricted to regulated entities.

If we are incorrect that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia, but rather, the relevant level of risk is that of a regulated energy network business, we submit that the reference to 'efficient financing costs' in the ARORO is to costs incurred (and therefore financing practices adopted) in a workably competitive market to finance an investment with that risk profile.

That is, regardless of what the relevant degree of risk is, once this risk benchmark is established, the assessment of efficient financing costs requires consideration of what financing practices would be engaged in by businesses operating in a workably competitive market, facing the relevant degree of risk. Such an interpretation of the term 'efficient financing costs' in the ARORO is consistent with the object of regulation itself, which is to simulate competitive market outcomes. This is because it is ultimately competition that drives efficient behaviour and is the benchmark that the NEL seeks to replicate. The 'workably competitive market' concept is described in more detail below.

Many of the issues dealt with in this chapter are the subject of applications for merits review of the AER's distribution determinations for the NSW electricity distributors (Ausgrid, Endeavour Energy, Essential Energy), the ACT electricity distributor (ActewAGL), and the NSW gas distributor (JGN) (NSW and ACT merits reviews). These issues include the approach taken by the AER to estimating the return on equity and the methodology to estimate the return on debt. The applications were heard in September and October 2015. Once the decision of the Tribunal has been published, we will review the decision and consider the implications, if any, of that decision for the determination the AER is required to make for us. To the extent we consider that the decision does have implications for its determination, we will make any submissions to the AER on those implications as soon as practicable after the Tribunal's decision has been published and considered by us.

8.2. Overview of rate of return

Table 8-1 compares the build-up of our proposed nominal vanilla weighted average cost of capital in this RRP with what we proposed in our Regulatory Proposal and the AER's Preliminary Decision.

Table 8-1: Comparison of rate of return parameters

	Regulatory Proposal	Preliminary Decision	RRP
Nominal vanilla weighted average cost of capital	7.38%	6.12%	8.70%
Return on debt	5.67%	5.33%	7.80%
Return on equity	9.95%	7.30%	10.05%
Risk-free rate	2.64%	2.76%	2.94%
Market risk premium	8.17%	6.50%	7.80%
Equity beta	0.89	0.70	0.91
Gearing	60.00%	60.00%	60.00%
Value of imputation credits (gamma)	0.25	0.40	0.25
Inflation	1.78-2.50%	2.50%	2.01%

The remainder of this chapter explains and justifies our revised proposal.

8.3. Return on debt

8.3.1. AER's Preliminary Decision

The AER's Preliminary Decision in relation to the return on debt is to maintain the return on debt methodology proposed in the rate of return guideline. That is, applied to our 2016 to 2020 regulatory period, the AER's Preliminary Decision on the return on debt is to:

- Estimate the return on debt using an on-the-day rate in the first regulatory year (2016) of the 2016 regulatory period, and
- Transition this rate into a trailing average approach over 10 years by updating 10 per cent of the return on debt each year to reflect prevailing interest rates.

The AER's Preliminary Decision on implementing the return on debt approach involves using:

- A benchmark credit rating of BBB+;
- A benchmark term of debt of 10 years;
- A simple average of the broad BBB rated debt data series published by the Reserve Bank of Australia (RBA) and Bloomberg, adjusted to reflect a 10 year estimate and other adjustments; and
- An averaging period for each regulatory year of between 10 business days and 12 months (nominated by the service provider) prior to 25 days before submission of the annual pricing proposal or reference tariff variation proposal.

8.3.2. Our RRP

As became clear from the detailed consideration of the return on debt issue in the NSW and ACT merits review processes, the method that the AER proposes to adopt in its preliminary decision for estimating the return on debt will not deliver a return on debt estimate which contributes to the achievement of the ARORO and the NEO. The correct construction of the ARORO is concerned with the financing costs and practices that are efficient in the economic sense, that is, the financing costs incurred, and practices adopted, in a workably competitive market.

We submit that the debt management practice that would be expected absent regulation is the holding of a staggered portfolio of fixed rate debt, the cost of which can be estimated by the trailing average approach. Given the intent of regulation is to replicate, insofar as possible, the outcomes that would be expected in workably competitive markets, the efficient financing costs to be estimated pursuant to clause 6.5.2 of the NER are required to be estimated using the trailing average approach and this approach should be adopted without any transition (AER Option 4).

The AER's approach to transitioning to the trailing average estimation method will lead to a return on debt allowance for the 2016 regulatory period that is below the efficient financing costs of a BEE for that period. This is because:

- The AER's approach proceeds on the incorrect premise that the efficient financing costs of a BEE are those that would be incurred under the financing practices that would have emerged under the previous regulatory approach to estimating the return on debt. The correct approach is to identify the efficient financing costs of a BEE, which are the costs that would be incurred in a workably competitive market (or, put another way, the costs that would be incurred absent regulation);
- The AER considered that the trailing average approach may be more reflective of the actual debt management approaches of non-regulated businesses and therefore, more likely to represent efficient financing practice.[47] The AER found that the efficient financing practice under the trailing average approach is to hold a staggered portfolio of fixed rate debt.[48] The efficient financing costs of a BEE are thus the costs associated with a staggered portfolio of fixed rate debt;
- Expert advice from CEG confirms that a 10 year trailing average approach would largely mimic the debt management strategy employed by unregulated infrastructure businesses[49]; and
- Given that the costs associated with a staggered portfolio of fixed rate debt are best approximated by a trailing average methodology, the immediate implementation of the trailing average approach to estimating the return on debt will provide an allowance that reflects efficient financing costs. Conversely, application of a transition that results in the return on debt being different from efficient financing costs will, by definition, lead to an allowance that is not commensurate with the efficient debt financing costs of a BEE.

For these reasons, we consider that the trailing average approach should be implemented immediately, with no transition. This is necessary to ensure that the return on debt allowance reflects the efficient financing costs of a BEE – i.e. the cost of financing a staggered portfolio of fixed-rate debt. Applying this approach, our calculation for the return on debt for each year of the 2016 to 2020 regulatory period is detailed in Table 8 2.

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[47] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, pp 108–111.

[48] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, pp 108–110.

[49] CEG, *Efficiency of Staggered Debt Issuance*, February 2013, [92], [97], [101] and [102].

Table 8-2: Cost of debt for 2016 to 2020 regulatory period

	2016	2017	2018	2019	2020
Cost of debt	7.804%	7.700%	7.508%	7.103%	6.708%

In accordance with the requirements set out in the AER's Rate of Return Guideline, our nominated debt averaging periods for the last four years of the 2016 to 2020 regulatory period are detailed in a confidential letter provided to the AER with this RRP.

We consider that the nominated averaging periods are as close as practical to the commencement of each regulatory year in the regulatory period, having regard for the NER requirements for us submitting annual pricing proposals to the AER. However, we seek the AER's approval to propose alternative dates closer to the time when they will take effect, should our nominated dates prove not to be practical.

Alternatively, even if the AER's approach of estimating efficient financing costs by reference to the financing practices that would emerge under regulation were correct, the appropriate approach would be to adopt a hybrid form of transition where only the hedged base rate component of the return on debt is subject to a transition (AER Option 3). This is because the AER has concluded that under the previous on-the-day approach to estimating the return on debt, an efficient financing practice would have been to engage in hedging of the base rate. By contrast, the AER has conceded that the debt risk premium (DRP) component of the return on debt cannot be (and could not have been) hedged, with the result that there is no reason for a transition to be applied to it.

If the hybrid transition is to be adopted, it would then be necessary to consider to what degree hedging would have been efficient. While the AER's reasoning assumes that the efficient level of hedging was 100 per cent, this is incorrect as a matter of fact and the evidence demonstrates that the efficient level of hedging of the base rate under an on the day approach to estimating the return on debt is significantly less than 100 per cent.

On any view of what are efficient financing costs, the AER's transition cannot be justified. Even on the AER's view of the correct approach to estimating efficient financing costs, and assuming that the BEE hedged the base rate 100 per cent, application of the AER's transition would lead to a mismatch between efficient financing costs and the regulatory allowance on the DRP component as the DRP could not have been hedged by a BEE.

In respect of implementation issues, we submit that the AER should:

- Adopt a benchmark credit rating of BBB, as per our original proposal
- Continue to adopt a benchmark term of 10 years;
- Follow the procedures set out in section 5 of the report that we submitted with our Regulatory Proposal entitled "Rate of Return on Debt: Proposal for the 2016 to 2020 Regulatory Period - Attachment to UE Regulatory Proposal" (dated 30 April 2015). In support of this we have submitted a revised report from Esquant with this RRP entitled "Estimating the yield on a benchmark corporate Nov/Dec 2015: Analysis to support the hybrid form of the transition to a trailing average rate of return on debt"; and
- Include a new issue premium of 27 basis points in the estimate of the return on debt for each regulatory year if the AER does not adopt the immediate transition approach.

8.4. Equity raising costs

8.4.1. AER's Preliminary Decision

The AER's Preliminary Decision in relation to the return on equity is based on the following reasoning:

- The AER considers that the Sharpe Lintner Capital Asset Pricing Model (SL CAPM) should be used as the foundation model to estimate the return on equity. We understand that the AER's reasons for adopting this approach are as follows:

  - The SL CAPM model is the current standard asset pricing model of modern finance both in theory and in practice;[50]
  - The SL CAPM is superior to all other models considered by the AER, in terms of estimating the return on equity of the BEE;[51]
  - Use of the SL CAPM as the foundation model, at least as applied by the AER, will not result in a downward biased estimate of the cost of equity capital;[52] and
  - Use of alternative models will not lead to an outcome which better achieves the ARORO.[53] The AER expresses a number of concerns in relation to these alternative models.
- An equity beta of 0.7, when applied in the SL CAPM, will deliver a return on equity that contributes to achievement of the ARORO. The AER considers that:[54]
  - A reasonable range for the equity beta based on evidence from samples of domestic energy network businesses is 0.4 to 0.7; and
  - Additional information taken into account by the AER – specifically empirical estimates for international energy networks and the theoretical principles underpinning the Black CAPM – indicate that an equity beta at the top of this range is appropriate.
- An MRP of 6.5 per cent reflects prevailing market conditions and contributes to achievement of the ARORO.[55]

  The AER determines a "baseline" estimate of the MRP of 6.0 per cent based on historical data, and then uses DGM analysis and other evidence to determine whether its estimate should be above or below that baseline. The AER considered that DGM evidence could justify a point estimate above the 6.0 per cent baseline, but did not support a point estimate above the top of the range implied by historical excess returns (6.5 per cent).

  The AER adopts a different interpretation of some of the empirical evidence to us, including:

  - The AER adopts a different interpretation of the historical excess returns data;
  - The AER does not agree that the Wright approach should be used to estimate the MRP. This is because the AER considers that the Wright approach is an alternative implementation of the CAPM, designed to produce information at the return on equity level;
  - The AER does not agree that independent valuation reports should inform MRP estimation (only the overall return on equity); and
  - The AER does not agree with SFG's construction of the DGM.
- The return on equity estimate from SL CAPM is broadly supported by:[56]
  - Estimates using the Wright approach;
  - Estimates from other market participants, including practitioners and regulators, particularly estimates used in Grant Samuel's recent report for Envestra;
  - The fact that it is above the prevailing return on debt; and
  - The fact that the regulatory regime to date has been supportive of investment.

[50] Preliminary Decision, p 3-32.
[51] Preliminary Decision, p 3-32.
[52] Preliminary Decision, p 3-62.
[53] Preliminary Decision, pp 3-32 – 3-33.
[54] Preliminary Decision, pp 3-36 – 3-37.
[55] Preliminary Decision, pp 3-34 – 3-35.
[56] Preliminary Decision, pp 3-39 – 3-40.

8.4.2. Our RRP

The method adopted by the AER in its Preliminary Decision does not result in a return on equity that is consistent with the ARORO.

The evidence before the AER is that its estimate is too low. In particular:

- The AER's estimate fails a number of its own cross-checks;
- It is below all available and relevant evidence as to the return on equity required by investors.
- This outcome is the result of:
  - The AER relying solely on the output of a model that is known to produce biased estimates, without the AER correcting for this bias;
  - The AER applying this model in a way that does not reflect market practice and which results in the return on equity simply tracking movements in the risk-free rate; and
  - Errors in interpretation and use of key evidence, including empirical evidence relating to the estimation of the MRP and equity beta.

We continue to believe that the ARORO is best achieved through an approach that properly has regard to estimates from all relevant return on equity models. In our Regulatory Proposal, we proposed that each of the SL CAPM, the Black CAPM, the Fama French Three Factor Model (FFM) and Dividend Growth Model (DGM) be estimated, and that these estimates each be given appropriate weight in deriving a return on equity estimate. Each of these return on equity models is independently used to derive an estimate of the required return on equity, while other relevant evidence is used to determine the best estimate of each parameter within these models. The outputs from each relevant model are then weighted equally to arrive at a return on equity estimate. Based on updated data to reflect prevailing market conditions, this approach leads to an estimate of the prevailing return on equity of 9.89 per cent. We maintain our view that this approach would best achieve the ARORO.

However, if the AER proposes to continue relying solely on the SL CAPM to estimate the return on equity, the AER must change the way it implements this model. It is clear from the evidence referred to above that the way in which the SL CAPM is applied in the Preliminary Decision leads to a return on equity that is not consistent with the ARORO and does not reflect prevailing market conditions. The AER does not properly recognise the weaknesses of the SL CAPM, nor does it account for these weaknesses in its application of the model. Further, the AER's practice of applying an effectively fixed ERP to a variable risk-free rate is not appropriate in current market conditions, since it leads to the return on equity moving in lock-step with changes in the risk-free rate. The result is that the AER's estimate of the return on equity is below the level of return required by the market, as indicated by the AER's cross-checks and other relevant evidence.

The accompanying expert report of Frontier Economics outlines an alternative approach that involves properly adjusting SL CAPM parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions. This involves: [57]

- Using a current measure of the risk-free rate (i.e. the prevailing yield on 10-year CGS). Over the 20 business days to 10 December 2015, this produces a risk-free rate of 2.94 per cent;
- Deriving the MRP in a way that gives appropriate weight to measures of the prevailing (current) MRP. Frontier recommends that 50 per cent weight be given to estimates of the prevailing MRP from the DGM, 40 per cent weight to historical measures and 10 per cent weight to evidence from independent expert reports (i.e. evidence of market practitioner estimates of the MRP). Of the 40 per cent weight that is assigned to historical measures equal weight (i.e. 20 per cent each) is given to estimates of historical excess returns and estimates using the Wright approach. Over the 20 business days to 10 December 2015, this produces an MRP of 7.8 per cent;
- Estimating a 'starting point' equity beta using a sufficiently large dataset. Frontier recommends including both US and Australian energy network businesses to ensure that the dataset is large enough to produce

[57] Frontier Economics, *The required return on equity under a foundation model approach*, January 2016.

robust estimates, with twice as much weight given to the Australian data. This produces a 'starting point' equity beta of 0.82; and

- Making two transparent and empirically based adjustments to the starting point equity beta estimate to account for the known shortcomings of the SL CAPM:
  - The first of these adjustments is to account for low beta bias, and draws on empirical evidence from the Black CAPM. Frontier recommends that 75 per cent weight be given to this adjustment, in recognition of the strong and consistent evidence of low-beta bias in the empirical literature (i.e. the adjustment is 75 per cent of the full adjustment that would need to be made to account for low-beta bias). This results in an adjustment from the starting point beta of 0.82 to a beta of 0.88; and
  - The second adjustment is to account for book-to-market bias (i.e. the failure of the SL CAPM to account for the effect of book-to-market ratio on stock returns). Frontier recommends giving less weight to this adjustment (25 per cent weight) in recognition that the evidence in relation to this bias is more recent. This results in a further adjustment, to an equity beta of 0.91.

This leads to an estimate of prevailing return on equity of 10.05 per cent for the 20 business days to 10 December.

Frontier observes that this estimate from the 'adjusted SL CAPM' is close to their estimate using the DGM, a model that is not affected by low-beta or book-to-market bias. Thus, the evidence from the DGM corroborates Frontier's adjusted SL CAPM estimate.

We consider that either the multi-model approach or the 'adjusted SL CAPM' approach (as described above) would be clearly preferable to the approach taken in the Preliminary Decision. For the purposes of this RRP, we adopt the adjusted SL CAPM approach.

Either of the alternative approaches we have put forward would represent a departure from the methods for estimating the return on equity set out in the Rate of Return Guideline. Our reasons for departure are set out in our supporting documentation.

8.5. Gearing

We maintain our proposed gearing ratio of 60 per cent, accepted by the AER in the Preliminary Decision, for the reasons set out in our Regulatory Proposal, and the Preliminary Decision. We note that this gearing assumption is broadly consistent with evidence of gearing ratios for businesses operating in a workably competitive market providing services similar to standard control services.

8.6. Gamma

8.6.1. AER's Preliminary Decision

In the Preliminary Decision, the AER adopts a similar approach to estimating gamma as in its recent decisions. This involves:

- Conceptualising gamma as the before-personal-tax and before-personal-costs value of imputation credits. In line with this conceptual approach, the AER estimates gamma as the product of the distribution rate and the utilisation value to investors in the market per dollar of imputation credits distributed (referred to as the "utilisation rate");[58]
- Deriving estimates of the distribution rate and theta for each of "all equity" and "listed equity".[59] For theta, the AER derives a number of different estimates, based on three different estimation methods:
  - The equity ownership approach, which uses ABS data to estimate the proportion of equity in Australian companies held by domestic investors;

[58] Preliminary Decision, p 4-16.

[59] Preliminary Decision, p 4-18.

    - Tax statistics, which indicate the proportion of distributed imputation credits that are redeemed by investors; and
    - Market value studies.
- Calculating gamma values based on its pairing of:
    - Its estimate of the distribution rate for all equity with its estimates of theta for all equity based on the equity ownership approach and tax statistics; and
    - Its estimate of the distribution rate for listed equity with its estimates of theta for listed equity based on the equity ownership approach and market value studies.
- Determining a range for gamma based on "the overlap of evidence from the equity ownership" approach (i.e. the overlap between the gamma ranges calculated by the AER based on the equity ownership approach for each of "all equity" and "listed equity").[60] The AER considered that the overlap of the evidence from the equity ownership approach suggests a value for gamma between 0.40 and 0.42; and
- Selecting a point within the range defined above by reference to evidence from tax statistics and market value studies. The AER observed that both tax statistics and SFG's market value study suggest a value for gamma lower than 0.4. On this basis, the AER adopted a value for gamma at the lower end of the range suggested by the overlap of the evidence from the equity ownership approach (that is, 0.4).[61]

8.6.2. Our RRP

The AER's approach to assessment of the empirical evidence in the Preliminary Decision is illogical and irrational.

In particular, we have concerns with the last two steps in the above process, being:

- The AER's determination of a range for gamma, based on the "overlap of the evidence from the equity ownership approach" (i.e. the overlap between the ranges for listed and all equity respectively), and
- The AER's selection of a point in that range based on the evidence from tax statistics and market value studies.

The first step is arbitrary and illogical, since it involves looking for an overlap between the ranges produced by two different measures and then taking that point of overlap as a binding constraint on the gamma estimate. Since the listed and all equity measures of the equity ownership rate are based on different datasets, there is no reason to expect that the ranges produced by these two measures would necessarily overlap. Indeed, as noted above, it is only because the AER takes such a long historical period to estimate its ranges for the equity ownership rate that the two ranges do overlap.

More importantly, there is no reason to expect that the value for gamma would lie at the point of overlap between these two ranges. The point of overlap indicates nothing about the value of gamma. Rather, it is driven by the AER's choice of time period for estimating ranges for the equity ownership rate. The point of overlap can be made larger or smaller (or made to disappear altogether) simply by varying the time period for analysis of the equity ownership rate.

The second step is similarly arbitrary and illogical, in that it uses different types of evidence to indicate where in a (illogical) pre-determined range the final estimate of gamma should lie. What the AER fails to recognise is that the equity ownership rate, the redemption rate and the market value are each measuring different things. The fact that the gamma estimates based on redemption rates and market value studies are both lower than the range of estimates from the equity ownership approach is to be expected, once it is borne in mind what these measures represent. Properly interpreted, the evidence from tax statistics and market value studies indicates that the value for gamma is (as it must by definition be) *below* the range from the equity ownership approach, not that it is at the lower end of that range.

[60] Preliminary Decision, p 4-19.

[61] Preliminary Decision, p 4-19.

As a result of this approach, the AER's estimate of gamma can only be reconciled with its range of estimates for the equity ownership rate. The AER's estimate of 0.4 is significantly above the values indicated by tax statistics and market value studies.

When correctly interpreted, the evidence presented in the Preliminary Decision demonstrates that:

- The distribution rate for the BEE is approximately 0.7;
- The upper bound for theta, as indicated by equity ownership rates and tax statistics, is approximately 0.45. This implies an upper bound for gamma of 0.32;
- The best estimate of the value of distributed imputation credits, on the AER's conceptual framework (i.e. ignoring personal costs), is 0.4. This implies a gamma of 0.28; and
- The best estimate of the value of distributed imputation credits, based on a proper application of the NER, is 0.35. This implies a gamma of 0.25.

This estimate reflects a proper interpretation of the NER and the best empirical evidence in relation to the value of imputation credits.

8.7. Inflation

8.7.1. AER's Preliminary Decision

In the Preliminary Decision, the AER adopted an inflation forecast of 2.5 per cent for the 2016 regulatory period. This is based on the methodology that has been adopted by the AER since 2008, which involves:[62]

- For the first two years of the regulatory period, taking the mid-point of the RBA *forecast* range for CPI inflation. For these two years, the RBA has published a forecast range of 2 – 3 per cent, with a mid-point of 2.5 per cent;[63] and
- For the following eight years, taking the mid-point of the RBA *target* range for CPI inflation, being 2.5 per cent (as this range is 2 to 3 per cent).

As RBA forecasts are only used for the first two years of the regulatory period, the inflation forecast derived using this methodology is primarily determined by the mid-point of the RBA's target range. This approach is reasonable where investors expect monetary policy to return inflation to—and maintain it at—the mid-point of the RBA's target range.

8.7.2. Our RRP

Recent market evidence demonstrates that the AER's current forecasting method is currently over-estimating inflation. In particular, the most recent Australian Bureau of Statistics (ABS) data shows that actual CPI inflation is well below the RBA's forecasts and target range – year-end CPI inflation for the June and September quarters was 1.5 per cent per annum, while for the March quarter it was 1.3 per cent.

[62] Preliminary Decision, p 3-256.

[63] RBA, *Statement on Monetary Policy*, November 2015, Table 6.1.

Table 8-3: Comparison of actual inflation with RBA and AER forecasts

Year ended	Actual inflation	RBA forecast (as at May of the prior year)	Forecast based on AER method (as at May of the prior year)
June 2013	2.4%	2 – 3%	2.5%
June 2014	3.0%	2 – 3%	2.5%
June 2015	**1.5%**	**2.5 – 3.5%**	**2.55%**

With RBA cash rates at record low levels and with near term rate cuts priced into financial markets, the RBA cash rate is close to the 'zero lower bound', with the result that the potential for monetary policy to stimulate economic activity and return inflation to the RBA's target range for CPI inflation is diminished.

The consequence of this is that:

- The AER's method is likely to result in an inflation forecast that is above market expectations of inflation over the regulatory period;
- The inflation forecast used to make adjustments to cash flows (based on the AER inflation forecast) is likely to be inconsistent with the forecast of inflation implied in the nominal rate of return (which reflects market expectations);
- The downward adjustment to depreciation cash flows is expected be too large – because the inflation forecast derived using the AER's method is expected to be higher than the actual inflation used to roll forward the RAB from 2016 to 2021—thus artificially depressing the overall return to investors; and
- Over the long-term, we will not be able to recover our capital costs.

We propose that an alternative forecasting method, based on market data, be adopted. The alternative method is referred to as the 'Fisher equation' method, or the 'breakeven inflation' forecasting method. Under this method, an estimate of expected inflation is derived using a simplified version of the Fisher equation, based on the difference in yields on nominal and inflation indexed CGS of the same maturity.[64]

The Fisher equation method was used by the AER prior to 2008. The AER only changed to its current method in 2008 as a result of market conditions at that time causing a scarcity of CGS. In its decision to move away from the Fisher equation method, the AER agreed with stakeholders that a market-based estimate of forecast inflation would be preferable, but concluded that due to market conditions at that time its market-based measure was likely to be unreliable. The AER therefore departed from the PTRM method for forecasting inflation (the Fisher equation method) and sought an alternative method that it considered would provide the best estimate of expected inflation.

The AER has determined that a methodology that is likely to result in the best estimates of expected inflation is to reference the RBA's short term inflation forecasts, that currently extend out two years, and to adopt the mid-point of the RBA's target inflation band beyond that period (i.e. 2.5 per cent).

We agree with the AER that a market-based estimate of inflation is preferable to an estimate based on the RBA forecasts and target range. A market-based estimate is more likely to be consistent with expectations of inflation reflected in the nominal rate of return, and more likely to be reflective of actual inflation over the regulatory period.

Further, the limitations that applied to the Fisher equation method in 2008 no longer apply.

In recent years, the current AER method has delivered similar outcomes to the Fisher equation method, because market expectations have been broadly in line with the RBA's forecasts and target range. Therefore, until now, there has been no pressing need for the AER to change its inflation forecasting method.

[64] CEG, *Measuring expected inflation for the PTRM*, June 2015, p 10; CEG, *Measuring risk free rates and expected inflation: A report for United Energy*, April 2015. CEG refers to this as the 'breakeven inflation' forecasting method. CEG notes that the equation it uses is a simplified version of the Fisher equation.

However, there is now a material divergence between the RBA forecasts / targets and market-based measures of inflation expectations. There has also been a material divergence between the RBA forecasts / targets and out-turn inflation over the past year.

During the development of the 2013 Rate of Return Guideline, forecasts produced using the Fisher equation were close to those produced by the AER's methodology. Therefore, at that time, it was unsurprising that stakeholders endorsed the continuation of the current approach when asked their views. The situation has since changed materially and the AER should not rely on outdated stakeholder support for its approach to satisfy itself that its approach is appropriate in the current environment. It is also worth noting that those views where never incorporated into the final guideline.

The evidence demonstrates that over the past year, actual inflation has been significantly lower than RBA forecasts and well below the RBA's target band.

Further, Dr Hird explains that over the medium term, it is more likely that actual inflation will be below the mid-point of the RBA's target range. Dr Hird notes that, with the RBA cash rate at record low levels, the power of monetary policy to spur economic growth and increases in the inflation rate is now more limited. Dr Hird concludes:[65]

> *In this context, it is reasonable to expect that investors perceive an asymmetry in the probability that inflation will be above/below the RBA's target, at least in the medium term. This means that, even if the 'most likely' estimate is for expected inflation to average 2.5% in the medium to long term, this is not the mean (probability weighted) estimate. That is, there is more downside than upside risk to inflation.*

This implies that it is no longer reasonable to expect inflation to revert to the middle of the RBA target range over the medium term. Accordingly, in current market conditions, a methodology that assumes medium term inflation would be at or around the mid-point of the RBA target range (as the current AER method does) is likely to over-estimate forecast inflation.

We therefore consider that now is an appropriate time for the AER to revert to the Fisher equation method for forecasting inflation as the better forecast method. Since the Fisher equation method provides a market-based estimate of inflation, use of this method will:

- Promote consistency between the inflation forecast used to make adjustments to cash flows and the forecast of inflation implied in the nominal rate of return;
- Provide for an inflation forecast that is more likely to be reflective of actual inflation over the regulatory period; and
- Provide businesses with a reasonable opportunity to recover their efficient costs over the long-term, since the inflation forecast used to calculate deductions from the revenue allowance will be more consistent with actual inflation, which is used to roll forward the RAB over time.

We propose to use the CEG implementation of the Fisher equation method, which places 60 per cent weight on a 5-year inflation forecast and 40 per cent weight on a 10-year forecast.[66] CEG explains that a 5-year forecast should be used for indexation of the portion of the RAB that is assumed to be debt financed, since the business' debt financing obligations over the 5-year regulatory period are in nominal terms. However for indexation of the equity-financed component of the RAB, a 10-year forecast should be used in order to effectively convert the 10-year nominal return on equity to a real return on equity.

We also adopt CEG's recommendation to substitute actual inflation into the 5-year forecast used for indexation of the debt-financed portion of the RAB, where actual observations are available.[67]

We therefore propose to apply an inflation forecast of 2.01 per cent, based on an application of the Fisher equation method over the 20 business days to 30 September 2015.

[65] CEG, *Measuring expected inflation for the PTRM*, June 2015, p 10.

[66] CEG, *Measuring expected inflation for the PTRM*, June 2015, section 3.

[67] CEG, *Measuring expected inflation for the PTRM*, June 2015, pp 24-25.

8.8. Supporting documents

Table 8-4 details the supporting documents that we have submitted as part of this RRP in relation to our proposed rate of return.

Table 8-4: Rate of return supporting documents

WACC category	From	Name of report / Comments / Document reference
Equity debt, gamma and inflation response	United Energy	Response to AER Preliminary Determination – Re: Rate of Return and Gamma (RRP 8-2)
Return on equity	Frontier	The required return on equity under a foundation model approach, January 2016 (RRP 8-3)
Equity beta	Frontier	Estimating the equity beta for the benchmark efficient entity, January 2016 (RRP 8-4)
CGS Yields and MRP	Frontier	The relationship between government bond yields and the market risk premium, January 2016 (RRP 8-5)
Gamma	Frontier	The appropriate use of tax statistics when estimating gamma, January 2016 (RRP 8-6)
Cost of Equity - Response to Partington and Satchell	Houston Kemp	The Cost of Equity: Response to the AER's Draft Decisions for the Victorian Electricity Distributors, ActewAGL Distribution and Australian Gas Networks, January 2016 (RRP 8-7)
Return on debt transition	CEG	Critique of the AER's approach to transition (RRP 8-8)
Return on debts data source	CEG	Criteria for assessing fair value curves, January 2016 (RRP 8-9)
Forecast inflation	CEG	Measuring expected inflation for the PTRM (RRP 8-10)
New Issue Premium	CEG	Critique of AER analysis of New Issue Premium (RRP 8-11)
Return on debt	Esquant	Estimating the yield on a benchmark corporate Nov/Dec 2015: Analysis to support the hybrid form of the transition to a trailing average rate of return on debt. Supporting information contained in the following documents (RRP 8-12): • TReuters BBB Rating AUD Credit Curve BMK (RRP 8-12a) • TR BBB Credit Curve – workbook (RRP 8-12b)

9. Estimated cost of corporate income tax

Key messages:

- We do not accept the AER's decision to apply gamma of 0.4 and defend proposal of 0.25 for the reasons explained in chapter 8 of this RRP.

9.1. Calculation of corporate income tax allowance

We accept the AER's approach to determining all elements of the corporate tax allowance, with the exception of the value of gamma of 0.25.

The components of the cost of corporate income tax calculation are presented in the PTRM and RFM as part of this RRP.

Table 9-1 details our proposed cost of corporate income tax, compared to our forecast in our Regulatory Proposal and the AER's Preliminary Decision.

Table 9-1: Cost of corporate income tax ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	31.9	32.8	31.9	24.9	27.6	149.1
AER Preliminary Decision	15.6	16.2	17.3	19.1	16.3	84.6
RRP	31.7	31.7	34.5	37.3	38.0	173.3

9.2. Appropriate interpretation of the value of imputation credits

As discussed in Chapter 8, the estimation method that we propose for gamma reflects the value which equity-holders place on imputation credits. We propose to use an observed distribution rate (0.7), which is consistent with the AER's Rate of Return Guideline, (the Guideline), and previous findings of the Australian Competition Tribunal (the Tribunal)[68]. We propose that the distribution rate be combined with the best estimate of theta from market value studies (0.35), which leads to an estimate for gamma of 0.25.

[68] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [22].

10. Incentive schemes

Key messages:

- We accept the AER's approach to calculating the 2011-2015 efficiency carry over, which commenced from 2009 – the "year six formula" – subject to:
  - The AER using the adjusted 2010 opex (i.e. adjusted to add back the JAM loss) consistent with the 2009 adjusted opex[69]; and
  - Adjusting for a reversal of $0.865 million for a licence fee paid to the Victorian Department of Treasury and Finance.
- We accept the AER's Preliminary Decision for its proposed STPIS but request that it correct an error in the incentive rates. The STPIS should apply the average annual energy consumption in the calculation of the incentive rates, rather than the total energy consumption for the regulatory period;
- We accept the proposed STPIS targets on the basis that the AER also retains its Preliminary Decision on our Augmentation capex, VCR and demand forecast; and
- We accept the AER's proposed F-factor targets and incentive rate.

10.1. Efficiency benefit sharing scheme

10.1.1. AER's Preliminary Decision

In its Preliminary Decision, the AER calculated the efficiency gains in 2011 differently to the approach we proposed in our Regulatory Proposal. The difference in approaches relates to whether the EBSS starts afresh for the 2011 to 2015 regulatory period, or whether it is a continuation of the 2006 to 2010 scheme.

The AER explained that its 2011 to 2015 Distribution Determination made it clear that 2011 should be treated as 'year 6' of the scheme, rather than 'year 1' of a new scheme. This decision is important because the efficiency gain formula for year 6 makes an adjustment for actual efficiency gains or losses in year 5 of the previous regulatory period. The AER's 2008 EBSS (Final EBSS) explains the year 6 formula as follows[70]:

> *As a DNSP's revenue determination for the following regulatory control period will be finalised prior to the end of the regulatory control period during which the EBSS is applied, the AER will estimate the actual opex required to calculate the efficiency gains or losses for the final regulatory year:*
>
> $A^*_5 = F_5 – (F_f – A_f)$
>
> *Where:*
>
> *F_f and A_f are the forecast and actual opex figures respectively in the base year (for example, if forecasts for the following regulatory control period are based on the actual opex in year 4, F_f is F_4 and A_f is A_4)*
>
> *Where differences arise between the estimate, A^*_5, and the actual opex amount incurred by a DNSP in the final regulatory year, A_5, the efficiency gain or loss in the first year of the following regulatory control period will be adjusted as follows:*
>
> $E_6 = (F_6 – A_6) – (F_5 – A_5) + (F_f – A_f)$

[69] This issue was addressed on a confidential letter dated 2 December 2015 from Stephanie McDougall of UE to Chris Pattas of the AER.

[70] AER, Electricity distribution network service providers, Efficiency benefit sharing scheme, June 2008, pages 5 and 6.

We accept the AER's Preliminary Decision that 2011 should be treated as year six, not year one and we agree that the efficiency gain for that year should be calculated in accordance with the formula in the Final EBSS.

We consider, however, that the AER has made an error in its application of the EBSS formula in calculating the 2011 efficiency gain.

10.1.2. Calculating the 2011 efficiency gain

As the AER used the fourth year of the 2006-2010 period (i.e. 2009) to forecast opex for the 2011 to 2016 regulatory period, the year 6 formula is:

$$E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$$

The AER's Final EBSS states[71]:

> *In calculating the efficiency gains or losses to be carried over, the measurement of actual opex over the regulatory control period must be done using the same cost categories and methodology used to calculate the forecast opex for that regulatory control period.*

In its 2011 to 2015 Distribution Determination, the AER adjusted our base year opex to reflect the actual costs of our outsourced service provider, Jemena Asset Management (JAM). The AER therefore adjusted our actual costs by adding back losses made by JAM in providing services under the Operating Services Agreement (OSA). This decision recognised that our actual costs were unsustainably low. This is discussed in the AER's 2011 to 2015 Distribution Determination in the following terms[72]:

> *Frontier Economics states it understands the OSA costs are unsustainable for the following commercial and regulatory reasons:*
>
> - *Commercial reason—JAM's costs in servicing the OSA appear to be higher than the price negotiated under the contract, which makes it unlikely United Energy could achieve a similar (low) price for these services in the future*
> - *[…]*
> - *[…]*
>
> *Frontier Economics acknowledges the first reason is not a concern with the AER's approach as:*
>
> > *"The AER's methodology utilises JAM's actual costs of servicing UED's network (rather than the price UED paid for these services under the OSA). This has the advantage of avoiding questions surrounding the potential under-recovery of JAM's costs under the present OSA contract. This means that the AER's estimated costs should not be understated as a result of referring to a historical underpriced contract that is unlikely to be available to UED in the future."*
>
> *[…]*
>
> *As noted above and confirmed by Frontier Economics, the AER's approach has adequately addressed this issue by adopting JAM's current actual costs rather than the current contract charges.*

To summarise the AER:

- Increased our actual reported 2009 opex by adding back the JAM losses (adjusted 2009 opex);
- Used the adjusted 2009 opex as the basis of its 2011-2015 opex forecasts; and
- Used the unadjusted 2010 opex in the EBSS calculation – this excludes the JAM loss in that year.

Importantly, the Final EBSS requires that:

[71] Ibid, page 6.

[72] AER, Victorian electricity distribution network service providers, Distribution determination 2011–2015 Appendices, Appendix I, October 2010, pages 158 and 159.

> *The efficiency gains or losses to be carried over, the measurement of actual opex over the regulatory control period must be done using the same cost categories and methodology used to calculate the forecast opex for that regulatory control period.* (Emphasis added.)

The same cost categories and methodology must be used because the scheme defines efficiency with reference to the AER's forecasts and the DNSP's prior year performance. If inconsistent data is used, the scheme will fail to accurately measure and reward efficiency improvements, which is the purpose of the scheme.

The AER has therefore made an error calculating our 2011 to 2015 carryover because it has used inconsistent data being:

- Our 2009 adjusted opex; and
- Our unadjusted 2010 opex – this excludes the JAM loss in that year.

The AER's use of our unadjusted 2010 opex is inconsistent with its use of the 2009 adjusted opex and the AER's 2011 to 2015 opex forecasts, which are also adjusted for the JAM losses.

The correct operation of the AER's Final EBSS requires the AER to use the "adjusted" 2010 opex (i.e. adjusted to add back the 2010 JAM loss).

Correcting for the error in the 2010 opex value results in a carryover amount of $36 million rather than $24.7 million, as set out in the AER's Preliminary Decision. We have explained this matter in a letter to the AER dated 2 December 2015.[73]

10.1.3. Licence fee removal

The AER should remove the licence fee from the reported costs for each year of the regulatory period. These costs are recovered via a separate part of the tariff formula and should not be included in the base year costs. The licence fee costs are separately reported in the Annual RIN (tab 12a. operating A) that has been provided to the AER. These licence fee costs are detailed in the table below and should be adjusted from the EBSS calculation:

Table 10-1: Licence Fee ($, Real 2015)

2009[74]	2010	2011	2012	2013	2014
-	470,253	143,164	59,479	284,251	(864,999)

These adjustment have been made in the EDPR Reset RIN included as part of this revised proposal. These adjustments have the effect of reducing the carryover amount of $24.7 million to $20.2 million. This also has the effect of increasing the base year opex costs and increasing the opex allowance by $4.3 million over the five year period. This is discussed in section 6.4.2 of this RRP.

It should be note that reported licence fee costs is a negative amount of $0.865 million and should be added back, which is an important factor for the 2014 base year cost calculation. This is a reversal of accrued amounts made during the 2006 to 2010 period and were only reversed out in 2014. As discussed in section 6.4.2, the delay in timing was due to an accounting error and corrected for in 2014. This original amount was previously adjusted for by the AER in the 2011 to 2015 final decision.

10.2. Service target performance incentive scheme

10.2.1. Incentive rates

The AER wrote to us on 10 November 2015 to confirm an error in tables 11-1 and 11-3 of its Preliminary Decision. It mistakenly derived the incentive rates for the STPIS using our total energy consumption for the regulatory period,

[73] See confidential letter dated 2 December 2015 from Stephanie McDougall of UE to Chris Pattas of the AER.

[74] Licence fee already excluded in the AER's 2011 to 2015 final decision

instead of the average annual energy consumption. The AER's STPIS outlines that the average annual energy consumption should be applied in calculating the incentive rates. We agree that this error should be corrected.

Our proposed STPIS incentive rates are detailed in Table 10-2.

Table 10-2: STPIS incentive rates

	Urban	Short rural
SAIDI	0.0007351880	0.0000402689
SAIFI	0.0517588883	0.0032882548
MAIFIe	0.0041407111	0.0002630604

10.2.2. Targets

We accept the STPIS targets detailed in Table 11.2 of the AER's Preliminary Decision on the basis that the AER also retains its Preliminary Decision on our Augmentation capex, VCR and demand forecast. Should the AER amend any of these elements in its Preliminary Decision then it should also amend the STPIS targets. This is because our Augmentation capex, VCR and demand forecast all reflect the fact that we will maintain our reliability performance in the 2016 to 2020 regulatory period and the AER's proposed STPIS targets are based on our average reliability performance over the last five years. There must be consistency, and alignment, between all of these elements in the 2016 to 2020 regulatory period.

10.2.3. Variation to Reliability Definitions

We proposed in our Regulatory Proposal changes to certain reliability definitions relevant to the STPIS.

Momentary interruption Events

The AER accepted our Regulatory Proposal to use Momentary Average Interruption Frequency Index event (MAIFIe) as the preferred measure of momentary reliability performance, rather than MAIFI.

We maintain our view that MAIFIe is the appropriate measure that should be used.

Duration of interruptions

We proposed in our Regulatory Proposal that the AER accept that the duration of momentary interruptions should be changed to conform to the *IEEE 1366 - 2012* standard of less than five minutes or the UK/European standard of less than three minutes.

The AER did not accept our proposal in its Preliminary Decision but indicated that it would review the definition of momentary interruptions when it reviews the STPIS.

We maintain our view that, consistent with the AEMC's September 2014 Final Report Review of Distribution Reliability Measures, three minutes is appropriate based on the available technology and network operational requirements.

We encourage the AER to revisit this matter and not to defer it until the scheme itself is reviewed. To do otherwise would mean that this revision would not apply to us until 2021.

Major event days and catastrophic events

We proposed in our Regulatory Proposal that the AER accept the approach detailed in the AEMC's Report that the exclusion of catastrophic events from the data set used by DNSP to calculate reliability measures should be based on the IEEE's 4.15 beta (β) method.

The AER did not accept our proposal in its Preliminary Decision but indicated that it would review the definition of momentary interruptions when it reviews the STPIS.

We maintain our view that, consistent with the AEMC's September 2014 Final Report Review of Distribution Reliability Measures, the IEEE's 4.15 beta (β) method should be adopted for the exclusion of catastrophic events.

We encourage the AER to revisit this matter and not to defer it until the scheme itself is reviewed. To do otherwise would mean that this revision would not apply to us until 2021.

Churn in feeder categories

We proposed in our Regulatory Proposal that the AER accept the AEMC's proposal to address the churn in feeder categories due to seasonal weather variations, by modifying the definition of an urban feeder. The change would replace actual maximum demand with weather normalised maximum demand. The practical effect of this change could provide greater certainty for some networks around investment decisions as performance is not subject to undue fluctuations due to feeder category churn. This would increase flexibility to apply feeder classifications on the basis of weather normalised maximum demand where there is likely to be a material benefit to customers.

The AER did not accept our proposal in its Preliminary Decision but indicated that it would review this matter when it reviews the STPIS.

We maintain our view that, consistent with the AEMC's September 2014 Final Report Review of Distribution Reliability Measures, the AER should make this change to address the churn in feeder categories.

We encourage the AER to revisit this matter and not to defer it until the scheme itself is reviewed. To do otherwise would mean that this revision would not apply to us until 2021.

10.3. Victorian Government F-factor Scheme

The AER approved our proposed f-factor scheme target at 134.9 fires per year – based on the average of the past five regulatory years.

We maintain this proposed target of 134.9 fires per year and accept the AER's proposed incentive rate of $25,000 per fire starts.

11. Pass through events

Key messages:

- We accept the alternative definitions in the AER's Preliminary Decision for the insurance cap event, the insurer's credit risk event and the natural disaster event.
- We also accept the AER's decision not to have a NECF event.
- We propose amendments to the AER's drafting of the terrorism and retailer insolvency events.

11.1. Introduction

In our Regulatory Proposal, we proposed the following nominated pass through events:

- Insurance cap event;
- Insurer's credit risk event;
- Natural disaster event;
- Terrorism event;
- Retailer insolvency event; and
- NECF event.

In its Preliminary Decision, the AER accepted the following events, albeit with revised definitions:

- Insurance cap event;
- Insurer's credit risk event;
- Natural disaster event;
- Terrorism event; and
- Retailer insolvency event;

The AER did not accept the NECF event.

We accept the alternative definitions in the AER's Preliminary Decision for the first three events listed above.

We also accept the AER's decision not to have a NECF event. The Victorian Energy Minister has advised us that the connections, connections charging and connection policy arrangements in the NER which relate to NECF will commence sometime by 1 January 2017. The Minister submitted legislation into the Victorian Parliament on 8 December 2015. The legislation is drafted so that the Minister determines the start date for the adoption of the connections framework in 2016 and no later than 1 January 2017. On this basis, we have proposed a NECF step change to implement the necessary changes in 2016.

We propose amendments to the AER's drafting of the terrorism and retailer insolvency events to address our concerns set out below.

Terrorism event

In recent months, the Bureau of Meteorology (BOM), a Government agency, has been the subject of cyber terrorism. We consider that the threat of such attacks is increasing and it should be clear that threats and disruption to computer systems and processes should also be included in the terrorism pass through event.

We proposed that the deliberate introduction of harmful code or viruses that create disruption to computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities should also be included clearly in the definition of a terrorism event. The AER responded that the risk of such attacks can and should be managed primarily through the prudent and efficient steps to protect our IT systems. The AER recognised that we are not precluded from applying for a pass-through under the terrorism event where there has been a cyber-terrorism attack.

The risks associated with these sorts of attacks are different with the higher integration of technology into the network at the low voltage level. We are conscious that these sorts of attacks are evolving and changing constantly and have proposed an opex step change to better meet the challenges ahead. In its Preliminary Decision, the AER did not approve the step change, despite these issues. Even ASIC recognise the increased risks and proposed criteria for ASIC registered companies to meet.

The AER has accepted that a terrorism event is consistent with a nominated pass through event and has also accepted that cyber-terrorism can be characterised within the event.

Our ability to reasonably prevent a terrorism event from occurring or to substantially mitigate the cost impact of such an event is limited. Whilst the occurrence of a terrorism event is largely beyond our control, we undertake a range of measures to reduce the likelihood of a terrorism event. We continue to review and assess the level of security at our sites in addition to undertaking security surveys. We also interact with a range of organisations and participate in various groups, including:

- The Victorian distributors' security group;
- Australian Cyber Security Centre;
- AusCERT; and
- Stay Smart Online.

We also highlight that:

> *the commercial market for insurance in Australia is insufficient to cover demand. While the Australian Government found in its 2012 Terrorism Insurance Act Review that the availability of insurance for terrorism is increasing, it nonetheless concludes that insurance for terrorism events remains insufficiently available at affordable rates:*[75]
>
> *…some commercial market capacity for terrorism insurance is re-emerging both internationally and domestically, although it remains insufficient to cover the available demand and is concentrated in supporting national pooled arrangements. Furthermore, there is insufficient capacity at reasonable prices for individual risks in Australia with the quantum of commercial market capacity being significantly below the current $13.4 billion scheme operated by the ARPC [Australian Reinsurance Pool Corporation].*[76]

We have proposed a number of amendments to the AER's drafting to:

- Include the attacks or disruptive activities to computer systems and networks;
- Remove the materiality reference as this is already covered in the NER for nominated events and positive change amounts so is unnecessary; and
- Change the AER's discretion to "may" to reflect that cyber terrorism may occur but an authority may not want to publically declare such an issue to major infrastructure and services given the essential nature of electricity. The government authority declaration should not need to be a condition precedent for the event to be considered by the AER. In the case of the BOM issue, we understand that the event occurred some months before any public announcement.

We therefore propose the following amendments to the AER's drafting.

A terrorism event occurs if:

> An act (including, but not limited to, the use of force or violence or the threat of force or violence, <u>attacks or other disruptive activities against, or the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities, or of the deliberate introduction of such harmful code or viruses</u>) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its

[75] Australian Government, Terrorism Insurance Act Review: 2012, p. 2. Available from: http://www.treasury.gov.au/~/media/Treasury/Publications%20and%20Media/Publications/2012/Terrorism%20Insurance%20Act%20Review%202012/downloads/Terrorism_Insurance_Act_Review_2012.ashx.

[76] CitiPower, 2016-2020 Price Reset, Appendix L, Managing Uncertainty, April 2015, p17

nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) ~~and which materially increases the costs to United Energy in providing direct control services.~~

Note: In assessing a terrorism event pass through application, the AER ~~will~~ may have regard to, amongst other things:

i. whether United Energy has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and

iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

Retailer Insolvency Event

The AER has accepted our proposal that the prescribed retailer insolvency event in the NER does not apply in Victoria and notes that we have drawn on the rule change proposal currently under consideration with the AEMC.

The AEMC has amalgamated three rule change proposals and is now looking at retailer insolvency, risk based credit support and other more innovative credit schemes, such as a retailer default fund and a liquidity support scheme. The AEMC intends to review a range of factors and make a decision in April or May 2016. We have reservations that matters that started as drafting corrections and a change of risk allocation or probability of default arrangements between the DNSP and retailer could now generate into a more significant change in these arrangements.

Victoria has not adopted the retail markets Chapter 6B of the NER, which covers network billing, payment terms and credit support. The current version of Chapter 6B is modelled on the arrangements operating in Victoria. These arrangements are based on the probability of defaults, maximum credit allowances and a risk sharing arrangement, which trades off the cost to the customer of the alternative regimes versus the cash-flow impact of a retailer insolvency supported. A key element of this risk-based approach is that it is supported by a robust pass through event. A retailer insolvency cost-pass through arrangement is required on the basis that the DNSP cannot:

- Prevent or avoid the risk by not dealing with a failing retailer;
- Mitigate the risk by refusing to transfer any more customers to that retailer and thereby add to the risk and extent of default or refuse to provide ongoing services to the retailers existing customers;
- The credit arrangements in Victoria are based on the fact that insuring against that risk is expensive and not seen as cost effective; and
- Self-insurance would not be a credible option because the relative infrequency and potentially high costs associated with retailer insolvency event create significant challenges for self-insurance for this type of risk.

We support the AER's position that the Victorian DNSPs should be afforded consistent protections to those available to DNSPs in NECF jurisdictions, particularly where the credit risk based approaches are adopted. We support the AER's position being:

- To apply the NER retailer insolvency event as in force from time to time; and
- For no materiality threshold to apply for this nominated pass through event should the AEMC adopt the COAG proposed corrected drafting to match the policy intent.

To this end, we recommend the following changes to the AER's drafting:

~~Prior to the commencement of the National Energy Customer Framework in Victoria,~~ Until such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria, **retailer insolvency event** has the meaning set out in the NER as in force from time to time~~.~~, except that:

(a) where used in the definition of 'retailer insolvency event' in the NER, the term 'retailer' means the holder of a licence to sell electricity under the Electricity Industry

Act 2000 (Vic) or an exemption from the requirement to hold a licence to sell electricity under that Act; and

(b) other terms used in the definition of retailer insolvency event in the Rules as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the NER or National Energy Retail Law not in force in Victoria, take their ordinary meaning and natural meaning, or their technical meaning (as the case may be).

For the purposes of this definition, the terms 'eligible pass through amount' and 'positive change event' where they appear in the NER are modified in respect of this retailer insolvency event in the same manner as those terms are modified in respect of the retailer insolvency event prescribed in the NER from time to time.

Note: This retailer insolvency event will cease to apply as a nominated pass through event on commencement of the relevant section of the National Energy Customer Framework in Victoria.

12. Annual revenue requirements, X-factors

Key messages:

- Our revised total revenue requirement for SCS has been calculated in accordance with the building block approach set out in the NER.
- We propose a positive X factor for our SCS in 2016 of 8.72 per cent (in accordance with the AER's Preliminary Decision), a negative X factor of 15.2 per cent per annum for 2017 to 2019 and an X factor of zero per cent for 2020.

12.1. Annual building block revenue requirement

Table 12-1 below summarises the composition of the unsmoothed revised building block revenue requirement for the 2016 to 2020 regulatory period.

Table 12-1: Total revenue requirements ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Return on Capital	179.6	193.0	204.9	210.2	213.3	**1,000.9**
Depreciation	79.8	81.2	93.3	102.1	106.9	**463.3**
Opex (incl. Debt Raising)	153.4	158.5	166.5	172.7	179.2	**830.4**
EBSS and other revenue amounts	4.9	17.7	6.3	9.7	(0.6)	**38.0**
Estimated cost of corporate income tax	32.4	33.0	36.7	40.4	42.0	**184.4**
Total Revenue Requirement (unsmoothed)	**450.0**	**483.4**	**507.7**	**535.1**	**540.8**	**2,517.1**

Each of the elements in Table 12-1 has been addressed in earlier chapters of this Regulatory Proposal. It should be noted that the total revenue requirement set out above is subject to a shared asset adjustment, as explained in the next section.

The total revenue requirements shown in Table 12-1 have been calculated in accordance with the PTRM, as required by clause 6.3.1(c)(1) of the NER.

12.2. X Factor

We propose a positive X factor for our SCS in 2016 of 8.72 per cent (in accordance with the AER's Preliminary Decision) and a negative X factor of 15.2 per cent per annum for 2017 to 2019 and an X factor of zero per cent for 2020. This approach is consistent with the provisions set out in clauses 6.5.9(b) and (c), and 11.60.3(b)(1) of the NER.

Table 12-2 below compares our revised X factors with those from our Regulatory Proposal and the AER's Preliminary Decision.

Table 12-2: X factors

	2016	2017	2018	2019	2020
Regulatory Proposal	(7.19%)	0.00%	0.00%	0.00%	0.00%
AER Preliminary Determination	8.72%	8.72%	0.00%	0.00%	0.00%
RRP	8.72%	(15.20%)	(15.20%)	(15.20%)	0.00%

It is important that the X factor in 2020 (being the final year of the 2016 to 2020 regulatory period) is zero. This will address the issue of artificially reducing our capital contributions under Guideline 14 and avoid the wealth transfer from our existing customers to developers (and other new customers) that we discussed in our Regulatory Proposal.

As discussed in our Tariff Structure Statement, we propose that there is no price change in 2016 and our proposed price reduction apply from 2017 when the new tariff structures under the TSS take effect.

13. Metering services

Key messages:

- We have revised our forecast to align with the final rule change for metering and meter competition commencement on 1 December 2017.
- We accept the AER's decision to remove one-off opex costs from 2014, however we have proposed our own actual costs rather than using Jemena as a proxy.
- The allocation of metering opex costs between SCS and ACS should reflect the following matters:
  - The cost allocation should be in line with the regulatory framework and correct service allocation;
  - The cost allocation should recognise the changed scope between CROIC and regulated metering services;
  - Any comparison of the costs of the Victorian DNSPs needs to recognise the different approaches they took to complying with the AMI obligations;
  - The possibility of Victoria adopting the competitive metering framework sometime in the future is not relevant in the transfer of the CROIC economic framework to the NER. The AER should provide for the efficient costs and correct allocation based on the current requirements;
  - A future ring fencing guideline is not relevant to the AER's decision, which must be based on the current requirements as at April 2016; and
  - Incorrect cost allocation could result in inefficient churn.
- We propose metering charges in the 2017 to 2020 period ranging from $62 to $74 per annum depending on the meter type.
- We propose the exit fee for a single phase, single element meter ranges from $449 in 2016 to $315 in 2020.

13.1. AER's Preliminary Decision

In its Preliminary Decision on our Annual Metering Charges, the AER:

- Accepted our proposal to apply a revenue cap form of control – we accept the AER's decision on the application of the revenue cap formula, including the application of the side constraints;
- Did not accept our proposed opening metering RAB value – we accept the AER's substitute value, noting that we will true this up based on 2014-15 actual capex;
- Did not accept our proposed metering capex forecast – we do not accept the AER's substitute forecast and have proposed a revised metering capex forecast in section 13.2.1 below;
- Did not accept our proposed metering opex forecast – we do not accept the AER's substitute forecast and have proposed a revised metering opex forecast in section 13.2.2 below;
- Accepted our proposed approach to depreciation, including a standard asset life of 15 years for remotely read interval meters and transformers and 7 years for IT, communications, and other metering related assets – we accept the AER's decision, but have proposed revised depreciation forecasts in section 13.2.3 below based on our revised metering RAB and capex values;
- Did not accept our proposed WACC – we do not accept the AER's substitute value and have proposed a revised WACC for metering services consistent with our revised WACC for SCS; and
- Did not accept our proposed metering annual revenue requirements – we do not accept the AER's substitute forecast and have proposed revised values in section 13.2.4 below. We have also detailed in sections 13.2.5 and 13.2.6 respectively our proposed X factors and indicative meter charges.

In its Preliminary Decision the AER:

- Rejected our proposed meter exit fees – we do not accept the AER's substitute and have proposed fees in section 13.3 below; and
- Accepted our proposed charges for Type 7 metering services – we accept the AER's decision and propose no further changes.

We have also proposed a manual meter read charge in section 13.5.

13.2. Annual Metering Charges

13.2.1. Capex

In its Preliminary Decision the AER rejected our capex forecast in our Regulatory Proposal.

Table 13-1 compares our forecast to the AER's Preliminary Decision.

Table 13-1: Metering capex forecasts 2016 to 2020 ($M, Real 2015)

	Regulatory Proposal	AER Preliminary Decision	AER adjustments
Meter installations	6.0	5.8	(0.2)
IT	16.5	7.5	(9.0)
Communications network	0.2	0.2	0.0
Total capex	**22.7**	**13.5**	**(9.2)**

Table 13-2 details our revised capex forecasts and the percentage changes from the AER's Preliminary Decision. We justify each sub-category of our capex forecast below.

Table 13-2: Revised forecast capex 2016-20 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Meter installations	3.0	1.1	0.6	0.7	0.7	6.0
IT	1.2	2.8	0.4	0.4	2.7	7.5
Communications network	0.1	0.1	0.0	0.0	0.0	0.3
Total capex	**4.3**	**4.0**	**1.0**	**1.0**	**3.4**	**13.7**

Metering installations

In our Regulatory Proposal, we explained that our capex forecasts for ACS metering were based on the following assumptions:

- Metering competition will start on 1 July 2017; and
- New meters installed on a regulated basis during the 2016 to 2020 regulatory period will be subject to the revenue cap.

In relation to the assumed start date for metering competition, the AER made the following observations[77]:

> *The AEMC's expanding competition in metering final rule change will be published in November 2015. As such, some of the details have yet to be confirmed. For jurisdictions that are part of the national metering framework, the new rules are expected to take effect from 1 December 2017. It is not clear at this stage the extent to which the Victorian Government will adopt the national framework.* [78]

We note that the AEMC's final Rule change was published on 27 November 2015. It confirms the amended commencement date of 1 December 2017 for metering competition. It follows that the meter purchase volume forecasts presented in our Regulatory Proposal need to be revised upwards to reflect a later start date for metering competition and the longer period under which new meters will be provided on a regulated basis.

Our revised capex forecast reflects this final rule change.

In relation to unit costs, the AER rejected our Regulatory Proposal and substituted costs from another DNSP, as explained below[79]:

> *United Energy note that its forecast unit cost increases are due to the loss of the AMI volume discount and a further increase advised by the meter manufacturer.*
>
> *We do not consider these reasons justify United Energy's higher unit costs. Our substitute unit costs are based on the proposed unit rates by another Victorian business in the 2016–20 regulatory control period. Firstly, the other Victorian businesses are in a similar position and are no longer in a rollout phase where they can obtain volume discounts. Secondly, contrary to United Energy's advice from its meter manufacturer, other Victorian businesses have been able to obtain lower unit costs for the same meter types which indicates to us that our substitute unit costs are currently commercially available.*

While the financial impact of the AER's lower unit cost is small, we do not accept the AER's decision. The AER has incorrectly assumed that we are able to secure meters at the same price as the lowest cost DNSP. In fact, this is unlikely to be the case because of: design differences in the meters; different contractual commitments with meter manufacturers; and particular exchange rate hedges that affect meter costs expressed in Australian dollars. As a consequence, meter purchase options that may be available to some DNSPs may be unavailable or uneconomic to others.

In our case, the following points should be noted:

- The volume discount for the purchase of 1 million meters achieved in our joint purchasing contract with Jemena is not available for the much smaller forecast volume required in the 2016 to 2020 regulatory period;
- The 2014 prices are approximately 10 per cent above the undiscounted prices of the original AMI contract with Secure from 2008-2009. This represents an increase in cost of approximately 2 per cent per annum from 2009 to 2014, which we consider to be a reasonable escalation over that time period;
- Secure can now supply an alternative new and likely cheaper product that is a modular meter. However, it would be inefficient for us to purchase this new product, rather than retain the older, more expensive design from 2009. In particular, the saving in costs obtained by purchasing the new meter at a lower price would be more than offset by the end-to-end test programs, which are required to verify that the meter can be registered in the AMI communications systems and data collected in accordance with the mandated service levels;
- The AER previously rejected our proposal to engage a second meter supplier on the basis that it would be "a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances."[80] Our decision to obtain the additional meter volume from our current supplier is consistent with the AER's previous determination on this issue. It is unclear why the AER now considers it appropriate for us to

[77] AER, Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 – Alternative control services, October 2015, page 16-26.

[78] AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

[79] Ibid, page 16-40.

[80] AER Victorian AMI 2012-15 Budget and Charges Determination, October 2011, page 162.

secure meters from a different supplier. We regard the mixing-and-matching of meters in order to reduce our costs by $0.2 million (as suggested by the AER's Preliminary Decision) as highly imprudent;

- The AER appears to have adopted AusNet Services' unit costs as a benchmark for our meter purchases. If this is the case, we do not support it given the known problems of AusNet Services' metering program. They have adopted a WiMAX communications solution, which is a different technology solution to Mesh radio, which has been adopted by the other DNSPs. The AER has already rejected millions of dollars incurred by AusNet Services for their metering program and should not now use them as the benchmark DNSP. The AusNet Services' meters and technology would not be compatible with our Mesh solution. Furthermore, the price for AusNet Services' meters excludes the communications module, whereas our unit price is for an integrated communication module which adds approximately $110 per meter.

In summary, our contract prices with Secure should be regarded as efficient, even if another DNSP (such as AusNet Services) expects to procure meters at a lower cost. Importantly, additional costs will be incurred, such as end-to-end testing, if a mix-and-match approach to meter purchasing is adopted.

Our contract prices with Secure reflect an AU:US exchange rate of 0.70. These are set out in Appendix D.1.

The AER accepted our proposed meter installation costs. These have been revised to take account of the extra five months to 1 December 2017.

IT Metering

We accept the AER's forecast of $7.5 million for the 2016 to 2020 regulatory period. This comprises the life cycle refresh of AMI head end systems, which manages the remote data collection and improved meter asset management systems.

We do not accept the AER's view that no metering capex should be allowed in relation to Power of Choice because of the uncertainty in relation to scope and timing. We have revised our cost estimates and has undertaken a detailed cost allocation assessment. These costs are now included in section 5.6.1 of this RRP.

Communications Network

In its Preliminary Decision, the AER accepted our modest communications metering capex forecast. We have adjusted this slightly to account for the delay to the commencement of metering competition of five months. The expenditure sought is now $0.27 million, up from $0.2 million in our Regulatory Proposal.

13.2.2. Opex

In its Preliminary Decision the AER rejected our opex forecast from our Regulatory Proposal. Table 13-3 compares our Regulatory Proposal forecast to the AER's Preliminary Decision.

Table 13-3: Metering opex forecasts 2016 to 2020 ($M, Real 2015)

	Regulatory Proposal	AER Preliminary Decision	AER adjustments
Efficient base year	120.0	120.2	0.2
Base year adjustment	0.0	(11.1)	(11.1)
Step changes	-	-	-
Debt raising	1.0	-	(1.0)
Labour escalators	0.3	-	(0.3)
Transfer to SCS	(94.4)	-	94.4

	Regulatory Proposal	AER Preliminary Decision	AER adjustments
Total Opex	**26.9**	**109.1**	**82.3**

a) Base year Opex

Table 13-4 provides a breakdown of our base year ACS metering opex compared with the AER's base year forecast in its Preliminary Decision.

Table 13-4: Revised metering opex base year forecast ($M, Real 2015)

	AER Preliminary Decision	RRP
Efficient base year	120.2	120.2
Base year adjustment	(11.1)	(8.1)
Total - revised base year	**109.1**	**112.1**
Recovered from SCS	0.0	61.9
Recovered from metering ACS	109.1	50.2

Further details are provided in the metering opex model that is included as part of this RRP. In the remainder of this sub-section, we comment on the adjustment to the base year opex for non-recurrent costs and the adjustment to SCS. We note that the AER has accepted the raw base year costs less the claims and manual meter reading costs as an efficient base year opex.

Base year Opex – non-recurrent cost adjustments

The AER has accepted our 2014 actual costs as the efficient base year, being our most recent audited accounts. The AER's Preliminary Decision reduces our base year by $2.2 million, or 9.25 per cent, which is the same percentage reduction proposed by Jemena to adjust for its non-recurrent opex base year. The AER considers Jemena's proposed adjustment to be a good benchmark to apply to us.

We accept the need for an adjustment to the base year given the status of the metering program in 2016 when compared to 2014. However, we do not accept the AER's $2.2 million adjustment. Rather, we have analysed our equivalent costs, which total $1.6 million, comprising $0.5 million for claims costs and $1.1 million for meter reading costs. We have therefore removed $1.6 million for non-recurrent costs in this RRP.

Base year Opex - Adjustments to SCS

The AER did not accept our proposed allocation of metering costs between SCS and ACS. The AER rejected any transfer to SCS on a number of grounds. These are addressed below.

The AER must correctly allocate costs in line with the regulatory framework

Incorrectly allocating the costs between SCS and ACS is contrary to the NEO, which is focused on promoting efficient investment decisions for the long term benefit of consumers. From an efficiency perspective, the revenue caps for SCS and ACS should reflect the costs of providing the relevant services, without any cross-subsidy between the two categories. This approach will promote economic efficiency (and the NEO) by providing cost reflective price signals to consumers and producers, consistent with the AEMC's recent initiatives in relation to network tariff design.

The NER service classification and the AER's Framework and Approach paper define the framework for cost allocation and our approved Cost Allocation Method gives effect to them. The RIN's are based on the Cost Allocation Method. The AER should not make a decision that is inconsistent with the regulatory framework. The

AER must review the allocation and the consistency with the regulatory framework and should not dismiss the review of the allocation. The AER is required to split the CROIC costs according to the correct service classification. The ring fencing guideline is irrelevant when the service classifications apply to the regulated distribution services and regulated metering services.

Changed scope between CROIC and regulated metering service needs to be recognised

Our Regulatory Proposal explained that the scope of the revenue capped metering services in the AER's framework and approach paper is substantially narrower than the scope of the regulated metering services under the CROIC. We highlighted that the scope of the cost recovery under the CROIC included the requirement to use best endeavours to change over almost 100 per cent of our meters to those which complied with the Victorian AMI functionality and service level specifications, including the consequential impacts on systems and processes to support the changes to network billing to cater for the high volumes of interval data and the move to several time varying tariffs where required[81]. The CROIC very clearly includes the establishment of capability to meet AMI obligations and the business as usual requirements.[82]

The Department of Economic Development, Jobs, Transport and Resources (DEDJTR) submission to the AER states:

> *DEDJTR considers that in deciding whether the transfer of costs is appropriate, the AER needs to apply the principle that was originally adopted in determining the first separate price control for metering services for the 2006-10 regulatory period*[83]:
>
> > *… the costs of those IT systems that are required for all customers, regardless of whose meter is installed, should be recovered through the [Distribution Use of System] DUoS price control … The costs of those IT systems that are required only for customers who have the distributor's meter installed should be recovered through the metering price control.*
>
> *DEDJTR accepts that the appropriate application of this principle may result in the transfer of some expenditure from metering services to other distribution services.*[84]

Our proposed approach in this RRP is consistent with that submitted by DEDJTR, whereby databases and systems that support all customers – regardless of who provides the meter – are allocated to SCS.

Comparison across Victorian DBs needs to recognise different approaches to complying with the AMI obligations

The Victorian DNSPs had different approaches to the AMI rollout and are at different points in their system lifecycles. We installed a purpose-built system, meter data store and processing capability and also upgraded our network billing systems. Some other DNSPs utilised existing IT systems and capability and enhanced these systems to cater for the roll out. These DNSPs may be undertaking the lifecycle replacement of the customer and billing systems in the 2016 to 2020 period and may be allocating much or all of these costs to SCS through system replacement projects. These differences significantly limit the extent to which the quantum of costs allocated between SCS and ACS will be consistent across the DNSPs. Nevertheless, the AER should adopt a consistent methodology to ensure that the costs of core DSNP functions (such as network billing) are properly attributable to SCS.

Victorian transition uncertainty is not an issue for the change of economic regulatory framework from CROIC to NER on 1 Jan 2016

In its Preliminary Decision, the AER raised the uncertainty of the Victorian Government's approach to metering contestability as a reason not to allocate costs appropriately to SCS and ACS.

As already noted, the AEMC released its Final Determination on expanding metering competition and related services on 26 November 2015. The final rule establishes the effective date for metering competition to commence on 1 December 2017. The final rule has already implemented the changes to the Victorian derogation to align with the 1 December 2017 date to eliminate any delay caused by the previous rules drafting which referred to an orderly transition for Victoria. These are the rules that apply to Victorian DNSPs. We need to ensure we are ready to

[81] United Energy, Revenue Capped Metering Services – Supporting Paper p14-15

[82] CROIC, Schedule 2.1 for United Energy

[83] Essential Services Commission, Electricity Distribution Price Review 2006-10, Final Decision Volume 1: Statement of Purpose and Reasons, October 2005, page 533

[84] Victorian Department of Economic Development, Jobs, Transport and Resources, Submission to Victorian electricity distribution pricing review – 2016-2020, p5

facilitate competition in our local area away from the regulated metering services. The AER needs to provide for the efficient costs to implement all aspects of the metering competition final rule so that we can facilitate the changes to our processes.

We cannot pre-empt the Victorian Minister's position on transitional arrangements or any other details with the move to metering competition and related services.

The uncertainty of the Victorian Government's approach to metering contestability shouldn't prevent costs being appropriately allocated between SCS and ACS. The economic framework under the CROIC ceases for the regulated services at the end of 2015 and the economic regulation of metering services commences under the NER. The AER should therefore approve the appropriate allocation of costs between services in its Final Decision.

Application of ring fencing guideline is not relevant

The AER's Preliminary Decision suggests that the appropriate allocation can be delayed and considered further after it develops its ring fencing guidelines. The AER suggests that all costs should be allocated to metering ACS in the interim.

The final metering competition rule also requires the AER to publish Distribution Ring Fencing Guidelines by 1 December 2016.[85] The AEMC considers that a DNSP taking on competitive services should have accounting and functional separation between direct control services and other services. The AER has previously stated (in its NSW exit fee decisions) that the NER prevents it from changing the classification of costs from ACS to SCS within a regulatory period. On this basis, the AER must determine an appropriate allocation of costs between SCS and ACS in its Final Decision before finalising its ring fencing guidelines. Systems that provide core functions for the distribution services must be allocated to SCS – including the provision, operation and maintenance of information technology applications, systems and infrastructure to receive and process metering data for network billing and to process the required industry notifications. As a DNSP, we require a meter data base for what will become all type 4 competitively provided meters, irrespective of who provides the meters.

Inappropriate cost allocation should not be used to encourage meter churn

The AER suggests that the impact of incumbent cost allocation approaches have the potential to affect competition from new entrants and competition between existing providers in Victoria. The incorrect cost allocation also has the effect of inappropriately allocating costs across service classifications and encouraging inefficient competition and premature loss of AMI services and data. This is not consistent with the NEO.

When we provide no regulated metering services, the metering data bases, meter reading frequencies, billing triggers and network billing based on the provided meter data still need to be undertaken for SCS. Costs need to be correctly allocated upon the unwinding of the CROIC and not in five years' time.

In summary, the AER's Preliminary Decision adopts an inappropriate allocation by continuing to apply the CROIC scope of service to metering ACS, even though the scope of metering ACS is narrower. We do not accept this approach for the reasons explained above.

Adjustment – IT Support Costs

The AER will be aware through the establishment of the initial and subsequent AMI budget determinations that we developed specific systems to meet the AMI requirements, including the data systems to store and manage the volume of interval data for network billing. The CROIC was established with this in mind given that the decision to proceed with the AMI roll out was made after the price review determination in 2006.

A new SAP system was installed in 2009 to process the volume of interval metering data for network billing purposes, manage the volume of claims and complaints arising from the AMI roll out. The SAP system was purchased as a bundle of modules, including the network billing, customer relationship and meter data store modules, consistent with the objective of minimising the cost of the rollout. The meter data store module has been turned on for the receipt of type 1-4 data and type 7 data in the SAP system near the end of 2015. The capex project will be completed at the end of 2015 and, as a consequence, the SAP system support costs should be appropriately allocated to SCS.

IT licencing and support costs for CROIC systems are allocated to meter ACS or SCS in the following manner.

[85] National Electricity Amendment (expanding competition in metering and related services) Rule 2015 No.12, new 11.86.8

Table 13-5: Proposed allocation between ACS and SCS

Activity	Cost allocation and rationale
Data collection for manually read type 5 meters, remotely read type 5 meters (AMI) and type 6 accumulation meters, including the meter data collection, storage and processing (substitution/estimation) of AMI data by the ITRON IEE system	ACS. This is a metering activity, which is not a core distribution service function.
Data storage for type 6 meters and the network billing capability for all meters types in the SAP system	SCS. This activity is required for network billing, which is a core distribution service function.
The receipt of meter data for current types 1-4 meters, the storage of the data and the network billing of this data	SCS. This is a business as usual distribution service function. The storage of the data and the associated network billing is undertaken in the SAP systems and databases is allocated to SCS

Our proposed allocation of IT systems is set out in Appendix D.2.

As noted above and in our Regulatory Proposal, the scope of the CROIC includes metering services and the provision, operation and maintenance of IT systems to manage the rollout, operate AMI technology and to process the data and meet our service obligations. These systems include not only the metering systems but, in our case, the provision of new connection point and standing data systems and network revenue management systems to cater for the increased volumes of metering data. For the reasons already outlined, the operational IT support costs of revenue management and connection point/standing data management should be transferred to SCS. The relevant IT opex is $12.3 million.

b) Rate of change

Rate of change and cost escalation for ACS metering services should be applied using the same method as for SCS.

We have therefore applied the same labour cost escalations to metering as the AER has accepted for our SCS. We have also adopted customer growth in 2016 and 2017 as a proxy for rate of change and given this a weight of 100 per cent. This is because customer growth best represents the driver of costs for metering. Rate of change is not relevant beyond this point due to metering competition.

We accept the AER's Preliminary Decision to apply a zero productivity adjustment to ACS metering services.

c) Step change – meter testing

We identified one step change for ACS metering services for the 2016 to 2020 regulatory period. This related to meter testing.

Our low voltage current transformer (LVCT) families were all tested in 2012-13 to meet the AER Compliance Bulletin No 6 – Instrument transformer testing. This was issued in December 2011 and the majority of future testing is not due until during the 2016 to 2020 regulatory period.

New LVCT meters were installed during 2014 and testing was not required and hence is not included in the base year costs.

In our role as Responsible Person, we must test metering installations in accordance with clause 7.6 and schedule 7.3 of the NER. We must have in place a Meter Asset Management Strategy approved by AEMO, in accordance with S7.3.1(c) of the NER as well as a meter testing plan registered with AEMO in accordance with S7.3.1(c)(2) of the NER. The NER requires all CT meters to be tested within five years. We are seeking a step change for the incremental costs of meter testing given that the costs in 2014 were low.

Meter testing costs include below:

- Sample testing of direct connected meters;
- 100 per cent testing of CT connected meters. CT inspections & admittance test also carried out as part of CT meter testing; and
- Sample testing of CTs.

We have sample tested all CT families from July 2012 to June 2013 in accordance with the new AEMO LVCT alternate testing methodology and the number of LVCT tests carried out during 2014 was minimal.

We have carried out 90 per cent of the non-AMI to AMI LVCT Meter replacements in 2014. As a prudent measure, we stopped testing of non-AMI LVCT meters in 2014, as they were to be replaced with new meters.

For these two reasons, the 2014 testing costs are understated and not suitable to use as the base for the period 2016 to 2020.

All the test quantities are calculated based on the above strategy and unit costs based on 2015 specialist meter testing contract rates. The costs presented are incremental to meter testing spend in 2014.

These cost are not recovered through meter growth numbers or labour price escalators and should therefore be addressed through a step change, as set out in Table 13-6.

Table 13-6: Meter testing – step changes ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Step change	0.2	0.2	0.2	0.2	0.2	0.9

13.2.3. Depreciation

The AER accepted our proposed approach to depreciation in our Regulatory Proposal, including the application of a standard asset life of 15 years for remotely read interval meters and transformers and seven years for IT, communications, and other metering related assets.

We accept the AER's decision, but have revised our depreciation forecasts based on our revised metering RAB and capex values.

13.2.4. Annual revenue requirements

Based on the above, Table 13-7 and Table 13-8 respectively detail our forecast metering RAB and annual revenue requirements for the 2016-20 regulatory period.

Table 13-7: Metering RAB for 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020
Opening RAB	213.2	189.4	164.9	136.8	118.0
Plus net capex	4.4	4.1	1.1	1.1	3.5
Less regulatory depreciation	(28.2)	(28.6)	(29.1)	(19.9)	(16.7)
Less disposals	-	-	-	-	-
Closing RAB	**189.4**	**164.9**	**136.8**	**118.0**	**104.8**

Table 13-8: Building block calculation for regulated metering services ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Return on Capital	18.2	16.0	13.8	11.1	9.3	**68.4**
Return of Capital (regulatory depreciation)	24.0	24.9	25.9	17.3	14.3	**106.3**
Operating Expenditure	10.5	10.6	10.6	10.8	10.8	**53.4**
Revenue Adjustments	0.0	0.0	0.0	0.0	0.0	**0.0**
Net Tax Allowance	0.0	0.0	0.0	1.2	4.0	**5.2**
Annual Revenue Requirement (unsmoothed)	**52.7**	**51.5**	**50.3**	**40.4**	**38.5**	**233.3**

Table 13-9: Building block calculation for regulated metering services ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Return on Capital	18.5	16.7	14.6	12.0	10.3	**72.2**
Return of Capital (regulatory depreciation)	24.5	25.9	27.4	18.7	15.8	**112.3**
Operating Expenditure	10.7	11.1	11.3	11.7	12.0	**56.7**
Revenue Adjustments	0.0	0.0	0.0	0.0	0.0	**0.0**
Net Tax Allowance	0.0	0.0	0.0	1.4	4.4	**5.7**
Annual Revenue Requirement (unsmoothed)	**53.7**	**53.6**	**53.4**	**43.7**	**42.5**	**246.9**

13.2.5. X Factor

We propose the X factors in Table 13-10 for the 2016 to 2020 regulatory period.

Table 13-10: Metering RAB for 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020
X factor	41.92%	29.59%	0.00%	0.00%	0.46%

13.2.6. Indicative meter charges

Table 13-11 shows our revised indicative meter charges for the 2016 to 2020 regulatory period, given our forecast annual revenue requirements and meter volumes. These indicative charges are based on metering competition commencing 1 December 2017. Our actual meter charges will be determined by the operation of the revenue cap formula.

Table 13-11: Revised indicative meter charges ($, Real 2015)

Meter Category	2016	2017	2018	2019	2020
Single phase single element	89.32	61.38	61.38	61.38	61.27
Single phase single element with contactor	89.32	61.38	61.38	61.38	61.27
Three phase direct connected meter	100.73	69.23	69.23	69.23	69.10
Three phase current transformer connected	106.71	73.34	73.34	73.34	73.21

13.3. Meter Exit Fee

We have updated our exit fees to reflect:

- The revised capex forecast in section 13.2.1;
- The cost of capital in chapter 8; and
- An increase in the administrative costs omitted from our Regulatory Proposal.

We highlighted in our Regulatory Proposal that our exit fee communications infill costs were not included on the basis that other initiatives such as network devices would be able to augment the communications.[86] The AEMC's Final Determination provides that, whilst the LNSP may install a network device, it must not impact the operation of the metering installation and it can be removed at any time if in the metering coordinator's reasonable opinion there is insufficient space in the metering facility when they seek to replace a meter. Whilst the AEMC has provided some measures to ensure there are appropriate rights to retain network devices, we consider there are still a number of practical difficulties and we are unable to rely on this approach to maintain the existing mesh robustness.

We have obligations to maintain the reliability of the mesh radio system as the meter numbers decline as the regulated metering business will have obligations to provide metering data in accordance with service level obligations. We have therefore added this component back into the administration costs.

In most cases the mesh will be self-healing, however we may need to bolster the communications network using micro-access points which provide an improvement to the communication network to address a tight locational problem. Given that the spread of communication loss across the network may be uneven, several relays may be needed where if the loss was all in one tight location one relay or micro access point could be used. The communications infill cost is forecast at $37 per meter, which is based on an 80 per cent use of micro access points and 20 per cent use of relays.

We are currently experiencing problems with the new competitive meter providers returning meters in the above 160MWpa market to our depots. Jemena included an additional allowance to locate missing meters and undertake a field trip to return the assets. Jemena proposed that 20 per cent of the time they would need to undertake a field trip to retrieve their assets and used the approved meter test fee as the base.[87] We propose this based on 20 per cent field visits and our approved meter test fee.

In our Regulatory Proposal, we proposed an administrative cost per meter attributable to retiring a market meter at the metering installation of $76.08. The AER accepted this forecast. We are now proposing that a communications infill and locate meter charge be included in the administrative cost per meter.

[86] UE Fees Application – AMI exit fee application, p9

[87] Jemena, 2016-20 Electricity Distribution Price Review Regulatory Proposal, Attachment 11-6, Metering exit fee application, p16

Table 13-12: Administrative cost per meter ($, Real 2015)

	AER Preliminary decision Administrative cost $/meter	RRP Administrative cost $/meter
Administrative costs - meter removal	76.08	76.08
Communications infill	-	37.00
Locate meter	-	49.60
Total	**76.08**	**162.68**

We propose the revised exit fees detailed in Table 13-13.

Table 13-13: Exit fee charge 2016 to 2020 ($, Real 2015)

Meter Category	2016	2017	2018	2019	2020
Single phase single element meter	449.86	411.01	372.60	338.43	315.09
Single phase single element meter with a contactor[2]	449.22	413.06	376.99	345.20	324.29
Three phase direct connected meter	502.50	459.83	419.41	383.19	357.85
Three phase current transformer connected	668.38	610.56	555.40	505.23	467.07

13.4. Type 7 metering services

The AER in its Preliminary Decision accepted our proposed type 7 metering services. We propose no further changes.

13.5. Manual meter read charge

We propose a manual meter read charge for customers that are not able to have their cyclical meter reading undertaken remotely. In the AER's Framework and Approach paper this was unclassified. We propose that this be treated as an ACS, fee based service. We note that the AER approved a manual meter read charge for CitiPower and Powercor in their Preliminary Decisions for these DNSPs.

We propose a manual meter read charge calculated on the same basis as the proposed special read charge for basic and interval meters, which the AER approved in its Preliminary Decision.

Table 13-14: Manual meter read charge ($, Real 2015)

Fee Based Service – field officer visits	Hours	Proposed Price $/meter read
Special read (basic meter)	Business hours	20.87
Special read (interval meter)	Business hours	20.87

13.6. Metering pricing formula

Our Regulatory Proposal suggested that the uncertainty regarding meter volumes could be addressed through an additional true-up mechanism in the revenue cap formula. It appears that the AER has not considered this proposal, and instead accepted our meter volume forecast on the following basis[88]:

> *For the Preliminary Decision, we have accepted United Energy's metering volume forecasts. We may revisit forecast metering volumes in the final decision if more information becomes available. For example, if the Victorian government confirms whether the derogation will expire or continue.*

We agree with the AER that the Victorian Government may extend the existing derogation, which would mean that metering competition does not commence in Victoria until 1 January 2021, being the start of the 2016 to 2020 regulatory period. As a consequence, we would be required to provide meters on a regulated basis throughout the 2016 to 2020 regulatory period, and purchase an increased volume of meters.

We note that the Revenue and Pricing Principles in the NEL require the AER to provide us with a reasonable opportunity to recover at least the efficient costs we incur in providing direct control network services. Given this requirement, and the on-going uncertainty regarding the commencement date for competition, we have proposed a pricing formula that allows us to recover our costs should there be a change to the date of metering competition in Victoria. This formula is provided below:

(1) $$MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i=1,...,n and j=1,...,m and t=1,...,5

(2) $$MAR_t = AR_t + T_t + B_t + C_t$$

(3) $$AR_t = AR_{t-1}(1 + CPI_t)(1 - X_t)$$

Where:

MAR_t

is the maximum allowable revenue in year t.

p_t^{ij} is the price of component i of tariff j in year t.

q_t^{ij} is the forecast quantity of component i of tariff j in year t.

AR_t is the annual revenue requirement for year t.

AR_{t-1} in 2016 is the annual smoothed revenue requirement in the Post Tax Revenue Model for the 2016 year in 2015 dollar value. After 2016 this is the ARt from the previous year.

T_t is the adjustments in year t for true-ups relating to the AMI-OIC.

B_t is the sum of annual adjustment factors in year t for the overs and unders account.

[88] AER, Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 – Alternative control services, October 2015, page 16-40.

C_t is the adjustments in year t for true-ups arising from the provision and installation of additional meters in the event of the Victorian Government extending the derogation.

CPI_t is the percentage increase in the CPI. This parameter will be decided in the final decision.

X_t is the X-factor in real terms in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. This parameter will be decided in the final decision.

We support the above formula, subject to the following qualifications:

- The revenue cap formula includes an adjustment T_t, which we assume will give effect to the transition charges provisions in clause 5L of the CROIC. We note that these provisions ensure that all relevant costs, including those associated with the Regulated Asset Base and opex, are captured as we transition from the regulatory arrangements under the CROIC to the AER's determination. To avoid any doubt, the revenue cap formula should specifically refer to the relevant CROIC provisions;
- The calculation of revenue should exclude any exit fees received. Exit fees are not revenue for the provision of metering services. Instead, an exit fee is a payment for retiring an existing remotely read interval meter (but not a Type 5 or Type 6 meter). The exit fee enables the DNSP to recover the remaining capital value of the interval meter, the commissioned telecommunications and information technology systems and also recover the additional operating expenditure in retiring the meter. The revenue from exit fees should be treated as follows:
    - The capital component of any exit fees received during the 2016 to 2020 regulatory period should be deducted from the Regulated Asset Base at the commencement of the subsequent regulatory period (being 1 January 2021). This approach is analogous to the regulatory treatment of asset disposals; and
    - The exit fee opex component represents the incremental costs of retiring meters and is not included in the revenue cap.
- Competition is assumed to commence on 1 December 2017. Consequently, the number of meters provided for new connections prior to the commencement of competition (and remunerated through the revenue cap) is also uncertain. To address this volume risk, we propose that meter purchase costs and revenues for new connections are excluded from the revenue cap. This approach is analogous to the standard regulatory approach to new connections for SCS. However, in the event that the Victorian Government extends the derogation beyond 1 December 2017, we have included a new term (C_t) in the formula to enable us to recover the costs of providing and installing additional meters; and
- We also propose that an adjustment is made to address differences between the forecast and actual number of existing meters that will be subject to competition (or churn) in the future . This adjustment can be included in the AER's true-up term B_t, and details of the proposed formula are provided in the supporting document, Revenue Capped Metering Services.

14. Fee-Based and Quoted Alternative Control Services

Key messages:

- We accept the AER's Preliminary Decision on our prices for all of our Quoted Services.
- We accept the AER's Preliminary Decision on our prices for our Fee-Based Services, except for new connections and temporary supplies, for which we propose that the AER accept the prices that we included in our Regulatory Proposal.

We accept the AER's Preliminary Decision on our prices for all of our Quoted Services.

We also accept the AER's Preliminary Decision on our prices for our Fee-Based Services, with the exception of those for:

- New connections – both business hours and after hours; and
- Temporary supplies – both business hours and after hours.

In its Preliminary Decision, the AER stated that:

> *Our analysis demonstrated that the majority of distributors proposed a time of approximately two hours or less—including travel time—to undertake the connection tasks. We note the large rural networks of Powercor and AusNet Services which have increased travel times compared to the other Victorian distributors were included in the distributors which undertake these tasks in approximately two hours or less time. Therefore, we consider a benchmark time of two hours is a reasonable estimate of time for United Energy to perform these tasks.*
>
> *We then compared United Energy's average unit cost rates for connection services during business hours against our maximum total labour rates. To do this we divided the applicable labour component of the proposed average unit cost rates by our benchmark time of two hours to deduce the hourly labour rates. Our analysis demonstrated that the hourly rates for some connection services exceeded our maximum total labour rates by over 40 per cent. As we consider our maximum total labour rates are efficient for providing these services, we do not accept United Energy's proposed average unit cost rates for these connection services during business hours.*

The AER calculated the component of our price for new connection that represents field work based on one person for two hours at a labour rate of $160.79, being $321.58. However, the AER failed to take into account that this is a two person function. This is the reason that the AER assessed our hourly rates to be comparatively high. Based on the AER's assumptions, it should have approved a rate of $643.16, plus an allowance for the other activities that contribute to the service. We proposed a lower price than this and therefore consider that the AER should accept our prices from our Regulatory Proposal. This same logic applies to temporary supplies, which also require two persons.

These prices are detailed in Table 14-1.

Table 14-1: Prices for New Connection and Temporary Supplies ($, Real 2015)

Service	Service type	Service code	Price
New connections	Single Phase single element	SPHCBG	$601.35
	Single Phase Two Element (off-peak)	SPH2EB	$601.35
	Three Phase Direct Connected	MPHCBG	$653.16
Temporary supplies	Standard Single Phase	TSCSPB	$601.35
	Multi Phase to 100A	TSCMPB	$653.16

15. Public lighting

Key messages:

- We accept the AER's Preliminary Decision on our forecast public lighting opex.
- We do not accept the AER's Preliminary Decision on our capex forecast and propose a revised forecast consistent with outcomes that we agreed with VicRoads and Local Councils.
- We have applied the same cost of capital that is detailed for SCS in chapter 8.

15.1. Total Revenue Requirement

Table 15-1 compares our revised forecast total revenue requirement for public lighting services to the forecasts in our Regulatory Proposal and the AER's Preliminary Decision.

Table 15-1: Public Lighting Total Revenue Requirement (Unsmoothed) ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	6.6	6.8	7.0	7.2	7.3	34.9
AER Preliminary Decision	6.1	6.2	6.3	6.3	6.3	31.2
RRP	6.1	7.5	6.9	7.0	7.0	34.5

15.2. Public Lighting Opex

We accept the AER's revised forecast in its Preliminary Decision for our Public Lighting opex of $17.9 million for 2016 to 2020. Table 15-2 compares our revised forecast opex to the forecasts in our Regulatory Proposal and the AER's Preliminary Decision.

Table 15-2: Public Lighting opex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	3.7	3.7	3.8	3.8	3.8	18.8
AER Preliminary Decision	3.5	3.6	3.6	3.6	3.6	17.9
RRP	3.5	3.6	3.6	3.6	3.6	17.9

15.3. Public Lighting Capex

We have consulted extensively with VicRoads and the Local Councils on our Public Lighting capex. At a meeting on 11 November 2015, we agreed to amend the current arrangements for the replacement of frangible poles. The current process requires VicRoads to supply all frangible poles and for us to provide the labour and equipment to install them. Our costs are recovered via the lighting price and VicRoads have separate arrangements in place to recover their costs. As from 1 January 2016, we agreed that we would begin to supply frangible poles as part of our standard price offering and amend our price accordingly.

As a result of this change, our capex forecast for the supply of frangible poles will increase by $36,000 per annum. This is made up of 30 poles at a cost of $1,200 per pole. This is based on information provided by

VicRoads. The price per main road lights increases by approximately $0.12 per year to accommodate these revised arrangements.

Table 15-3 compares our forecast capex to the forecasts in our Regulatory Proposal and the AER's Preliminary Decision.

Table 15-3: Public Lighting capex ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	2.4	2.5	2.6	2.6	2.8	12.9
AER Preliminary Decision	1.9	2.0	2.1	2.1	2.2	10.3
RRP	1.9	2.0	2.1	2.2	2.2	10.4

15.4. Capital charge

We agree with the AER that the cost for capital applied for SCS should also be applied for public lighting. Our proposed cost of capital has been updated and is detailed in chapter 8.

We accept the AER's proposed approach to determining regulatory depreciation for our Public Lighting services.

Table 15-4 compares our forecast capital charge (being the sum of our regulatory depreciation and return on capital allowances) to the forecasts in our Regulatory Proposal and the AER's Preliminary Decision..

Table 15-4: Public Lighting return on capital ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Regulatory Proposal	2.9	3.1	3.2	3.4	3.6	16.2
AER Preliminary Decision	2.6	2.6	2.6	2.7	2.7	13.2
RRP	3.2	3.3	3.3	3.3	3.4	16.6

15.5. Summary of revised prices

Table 15-5 details our forecast public lighting real price movements – being the implied X factors – for 2016 to 2020 in order to recover our total revenue requirement detailed in Table 15-1.

Table 15-5: Public Lighting real price movement – implied X factors ($M, Real 2015)

	2016	2017	2018	2019	2020
Existing Lights					
Mercury Vapour 80 watt	57.59	65.67	64.14	67.65	71.42
Sodium High Pressure 150 watt	72.09	84.17	83.36	85.83	90.14
Sodium High Pressure 250 watt	73.92	86.28	80.32	87.87	92.24
Fluorescent 2x20 watt	74.28	84.72	82.74	87.27	92.14
Fluorescent 3x20 watt	74.28	84.72	82.74	87.27	92.14

	2016	2017	2018	2019	2020
Mercury Vapour 50 watt	85.23	97.20	94.92	100.13	105.71
Mercury Vapour 125 watt	85.23	97.20	94.92	100.13	105.71
Mercury Vapour 250 watt	67.27	78.52	73.09	79.96	83.94
Mercury Vapour 400 watt	93.14	108.71	101.20	110.72	116.23
Mercury Vapour 700 watt	93.14	108.71	101.20	110.72	116.23
Sodium High Pressure 70 watt	126.11	143.83	140.46	148.16	156.42
Sodium High Pressure 100 watt	79.29	92.59	91.70	94.42	99.15
Sodium High Pressure 400 watt	93.14	108.71	101.20	110.72	116.23
Metal Halide 70 watt	97.32	113.63	112.54	115.88	121.69
Metal Halide 100 watt	97.32	113.63	112.54	115.88	121.69
Metal Halide 150 watt	97.32	113.63	112.54	115.88	121.69
Metal Halide 250 watt	99.80	116.48	108.43	118.62	124.53
Metal Halide 400 watt	99.80	116.48	108.43	118.62	124.53
Energy Efficient Lights					
T5 2X14W	38.46	39.86	38.46	38.46	38.46
Twin 24w Fluorescent	38.46	39.86	38.46	38.46	38.46
32W Compact Fluorescent	38.46	39.86	38.46	38.46	38.46
42w Compact Fluorescent	38.46	39.86	38.46	38.46	38.46

16. Negotiating Framework

Key messages:

- We do not accept the AER's proposed amendments to the dispute resolution arrangements in our Negotiating Framework. Our proposed dispute resolution arrangements are identical to those that the AER approved for the 2011 to 2015 regulatory period.

We submitted a Negotiating Framework to the AER as part of our Regulatory Proposal.

Clause 10 of our proposed Negotiating Framework states that:

> *(a) All disputes between the parties as to the terms and conditions for the provision of a negotiated distribution service are to be dealt with by United Energy's dispute resolution processes in the first instance.*
>
> *(b) Should United Energy' internal dispute resolution processes prove unsuccessful, disputes will be dealt with by the AER in accordance with Part 10 of the NEL and Chapter 8 of the Rules, as applicable.*

This clause 10 is identical to that which the AER approved for our Negotiating Framework for the 2011 to 2015 regulatory period.

The AER's Preliminary Decision on our proposed Negotiating Framework for the 2016 to 2020 regulatory period was as follows:

> *We propose a variation to United Energy's proposed negotiating framework for the 2016–20 regulatory control period. Specifically, our Preliminary Decision is to:*
>
> - *Delete section 10 (a) of United Energy's negotiating framework which provides that 'all disputes between the parties as to the terms and conditions for the provision of a negotiated distribution services are to be dealt with by United Energy's dispute resolution processes in the first instance'.*
> - *Amend section 10 (b) of United Energy's negotiating framework to state that 'all disputes arising during the course of the negotiation shall be dealt with in accordance with Part 10 of the NEL and Part L of Chapter 6 of the NER'.*
> - *Otherwise adopt United Energy's proposed negotiating framework.*

We understand that the AER's Preliminary Decision is based on clause 6.7.5(c)(6) of the NER that requires that a negotiating framework must specify:

> *a process for dispute resolution which provides that all disputes as to the terms and conditions of access for the provision of negotiated distribution services are to be dealt with in accordance with the relevant provisions of the Law and the Rules for dispute resolution.*

We consider that clause 10 of our proposed Negotiating Framework fully addresses clause 6.7.5(c)(6) because sub-clause (5) refers out to the relevant requirements of the NER. Clause 10(a) is required in our Negotiating Framework in order to provide us with the opportunity to resolve any dispute ourselves before it is referred externally.

We therefore do not accept the AER's proposed amendments as they would mean that all disputes are referred, in the first instance, to the AER. This would add unnecessary complexity to the negotiating process and would impose an unwarranted regulatory burden both on us and the AER.

We further note that, to the best of our knowledge, no stakeholders have identified problems with the current arrangements. This further suggests that no change is warranted to the current arrangements.

We therefore propose that our wording of section 10 of our current Negotiating Framework be retained in our Negotiating Framework for the 2016 to 2020 regulatory period.

17. Confidentiality

Title, page and paragraph number of document containing the confidential information	Description of the confidential information.	Topic the confidential information relates to (e.g. capex, opex, the rate of return etc.)	Identify the recognised confidentiality category that the confidential information falls within.	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
RRP 8-1 Table in letter from UE to AER of 6 January 2016 regarding debt averaging period	Averaging period for use in calculating the return on debt	Rate of return	Market sensitive information	The information is confidential because it specifies the date/s when UE expects to raise debt.	Disclosure of UE's proposed dates on which it proposes to raise debt would potentially influence the behaviour of prospective lenders.	As the Cost of Debt is a key input to the Rate of Return UE receives on its assets, not receiving an efficient market rate will have a detrimental impact on the price customers will ultimately pay for the distribution of electricity.
RRP 5-22 OT Security PJ1500 Complete document, pages 1-19	Security controls to address increasing cyber and physical security risks. Enhancements to security zone substation sites, the AMI network and Field devices.	Security	Information affecting the security of the network	If any of this information is publicised then UE's Network security would be at risk.	Exposing this information potentially indicates UE's security weaknesses and vulnerabilities to potential attack	Any attack that successfully breaches UE's security would potentially cause outages, increase safety risks and have a significant adverse impact on consumers. There is no significant benefit to consumers in identifying areas of security that require attention.

Title, page and paragraph number of document containing the confidential information	Description of the confidential information.	Topic the confidential information relates to (e.g. capex, opex, the rate of return etc.)	Identify the recognised confidentiality category that the confidential information falls within.	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
RRP 5-13 Management (ISSAM) (CCTV) UE PL 2401 Throughout the document Page 10 text highlighted Page 38 text highlighted Page 45 table highlighted	All references to sensitive infrastructure locations used to operate and control the UE network such as zone substation sites have been removed.	Infrastructure locations	Security.	Information affecting the security of the UE network.	If disclosed, the information could be used by people with malicious intent to target UE's network via physical attacks, potentially succeeding in disrupting supply or adversely impacting the safe operation of the network.	UE believes there is limited public benefit in the disclosure of the locations of sensitive infrastructure used by the electrical distribution network and the detriment of disclosure is greater than any public benefit.
RRP 5-13 Management (ISSAM) (CCTV) UE PL 2401 Table 5 - Pages 35 - 36	All references to sensitive risk rating information on infrastructure used to operate and control the UE network have been removed.	Infrastructure security risk ratings	Security	Information affecting the security of the network.	If disclosed, the information could be used by people with malicious intent to target UE's network via physical attacks, potentially succeeding in disrupting supply or adversely impacting the safe operation of the network.	UE believes there is limited public benefit in the disclosure of the locations of sensitive infrastructure used by the electrical distribution network and the detriment of disclosure is greater than any public benefit.
RRP 5-13 Management (ISSAM) (CCTV) UE PL 2401 Table 16, 17 - Page 51-52	All references to sensitive pricing information	Sensitive price information	Market sensitive cost inputs	Market sensitive cost inputs – information such as supplier prices or information that would affect UE's ability to obtain a competitive price in future infrastructure transactions, such as tender processes.	Prices are commercial-in-confidence. Disclosure of external Service Provider unit cost information would have the potential to adversely affect future pricing processes.	There would be a net public detriment if this information were disclosed. Possible impacts include the distortion of competition among suppliers, leading to prices being higher than may otherwise be the case. Such outcomes would be to the detriment of the long term interests of consumers.

Title, page and paragraph number of document containing the confidential information	Description of the confidential information.	Topic the confidential information relates to (e.g. capex, opex, the rate of return etc.)	Identify the recognised confidentiality category that the confidential information falls within.	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
RRP 8-12a - TReuters BBB Rating AUD Credit Curve BMK	Images of the Thomson Reuters BBBAUD benchmark credit curve. The images were captured during November and December 2015. The images provide information about the curve components at the relevant times.	Rate of return	"Other".	This information has been retrieved from a subscription service, notably Thomson Reuters Eikon, with Datastream for Office. The information is being provided to the AER as a courtesy, and so as to ensure that the information can be relied upon as review related material. It is expected that the ACCC/AER will take out its own subscription to the particular Thomson Reuters product.	UE would be in breach of the conditions of an agreement between DUET and Thomson Reuters.	UE is not permitted to make the information freely available to the public.

Title, page and paragraph number of document containing the confidential information	Description of the confidential information.	Topic the confidential information relates to (e.g. capex, opex, the rate of return etc.)	Identify the recognised confidentiality category that the confidential information falls within.	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
RRP 8-12b Copy of Credit CurveTS_for AER_31122015vals - Excel workbook	Historical end-of-day data pertaining to the BBBAUD credit curve. The closing values for the yields and spreads of the credit curve are shown. Other associated variables are also provided. Two separate worksheets show, respectively, the historical bid yields and the ask yields for the component bonds. The component bonds shown are those which have recently contributed to the make up the curve.	Rate of return	"Other".	This information has been retrieved from a subscription service, notably Thomson Reuters Eikon, with Datastream for Office. The information is being provided to the AER as a courtesy, and so as to ensure that the information can be relied upon as review related material. It is expected that the ACCC/AER will take out its own subscription to the particular Thomson Reuters product.	UE would be in breach of the conditions of an agreement between DUET and Thomson Reuters	UE is not permitted to make the information freely available to the public.

18. Certifications

Our Directors and Chief Executive Officer have certified that the total revenue requirement for the regulatory control period, and the annual revenue requirement for each regulatory year, as set out in the building block proposal of this Revised Regulatory Proposal, have been properly calculated using the post-tax revenue model on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of Chapter 6 of the NER.

These certification statements are provided as an attachment to this Regulatory Proposal.

19. Glossary

Abbreviations	
ABS	Australian Bureau of Statistics
ACIF	Australian Construction Industry Forum
ACR	Automatic circuit reclosers
ACS	Alternative Control Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As low as reasonably practicable
AMI	Advanced Metering Infrastructure
AMI-OIC	Advanced Metering Infrastructure Order In Council
ARORO	Allowed rate of return objective
ASIC	Australian Securities and Investment Commission
Augex	The AER's Augex model
B2B	Business to business
BEE	Benchmark efficient entity
BOM	Bureau of Meteorology
CAIDI	Customer average interruption duration index
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CA RIN	Category Analysis Regulatory Information Notice
CBRM	Condition based risk management
CCTV	Closed circuit television
CEO	Chief Executive Officer
CEES	Capital Expenditure Explanatory Statements
CES	Cultural or environmental significance
CESS	Capital Expenditure Sharing Scheme

Abbreviations	
CERT	Computer Emergency Response Team
CGS	Commonwealth Government security
CPI	Consumer price index
CPP	Consumer Challenge Panel
CRM	Customer Relationship Management
CROIC	Victorian Government Cost Recovery Order-in-Council
CT	Current Transformer
DAE	Deloitte Access Economics
DAPR	Distribution annual planning report
DEDJTR	Department of Economic Development, Jobs, Transport and Resources
DFADCAA	Distribution Fault Anticipation Data Collection and Analytics
DGM	Dividend Growth Model
DMIA	Demand management incentive allowance
DMIS	Demand management incentive scheme
DMA	Dromana
DMS	Demand management system
DNSP	Distribution network service provider
DR	Demand response
DRP	Debt risk premium
DSP	Demand Side Participation
DUOS	Distribution use of system
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity distribution price review
EG	Embedded generation
EHAS	Ecological, historical or aesthetic significance
ENM	Embedded Network Managers
ERP	Enterprise Resource Planning

Abbreviations	
ESCV/ESC	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EWOV	Energy and Water Ombudsman Victoria
F-factor	Victorian Government Fire-factor scheme
FFM	Fama French Three Factor Mode
FRMP	Financially responsible market participant
FTE	Full time equivalent
GSL	Guaranteed Service Level
GWh	Gigawatt Hour
HBRA	High bushfire risk area
HROF	High risk of failure
HTS	Heatherton Terminal Station
HV	High voltage
HV ABC	High voltage aerial bundled cable
ICT	Information and Communications Technology
JAM	Jemena Asset Management
LCS	Life Cycle Strategies
LNSP	Local network service provider
LV	Low voltage
LVCT	Low voltage current transformer
M	Millions
MAIFI	Momentary average interruption frequency index
MAIFIe	Momentary Average Interruption Frequency Index event
MC	Metering coordinator
MCR	Marginal cost of reinforcement
MDP	Metering data provider

Abbreviations	
MDPP	Metering Data Provision Procedures
MED	Major event day
MPB	Metering provider category B
MRP	Market risk premium
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Total Factor Productivity
MTN	Mornington
MVA	Mega Volt Ampere.
MW	megawatt
NECF	National Energy Customer Framework event
NEL	National Electricity Law
NEM	National Energy Market
NEO	National Electricity Objective
NMI	National metering identifier
NER (Rules)	National Electricity Rules
OH	Overhead
OMR&R	Operation, maintenance, repair and replacement
Opex	Operating expenditure
OSA	Operating Services Agreement
OT	Operational technology
PIAC	Public Interest Advocacy Centre
PTRM	The AER's Post-Tax Revenue Model
PV	Photovoltaic
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RCGS	Remote control gas switches
REFCLs	Rapid Earth Fault Current Limiters
Repex	The AER's Repex model

Abbreviations	
RFM	The AER's Roll-forward Model
RIIO	Revenue = Incentives + Innovation + Outputs
RIN	Regulatory Information Notice
RRP	Revised Regulatory Proposal
RTS	Richmond Terminal Station
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAPN	SA Power Networks
SCADA	Supervisory control and data acquisition
SCS	Standard Control Services
SWER	Single wire earth return
SoW	Statement of Works
SL CAPM	Sharpe Lintner Capital Asset Pricing Model
STPIS	Service Target Performance Incentive Scheme
TFP	Total Factor Productivity
TSS	Tariff Structure Statement
UE	United Energy
UG	Underground
VBRC	Victorian Bushfires Royal Commission
VCR	Value of Customer Reliability
VGA	Victorian Greenhouse Alliances
WACC	Weighted average cost of capital
ZSS	Zone substation

20. Supporting documentation

Table 20-1 details the supporting documents that we are submitting as part of this RRP. We have provided cross-references to the sections of this RRP to which each document relates.

Table 20-1: RRP Supporting documents

Document reference	Document name	RRP sub-section reference
Connections		
RRP 5-1	CIC Resubmission - Projects	5.4,5.4.1,5.4.2
RRP 5-2	Unit rate and volume analysis 2016	5.4,5.4.1,5.4.2
Repex		
RRP 5-3	Assets at High Risk of Failure Assessment UE PL 2044	5.5.1 to 5.5.5
RRP 5-3a	– HROF - UE PL 2044 - Model V6.0	5.5.3
RRP 5-4	Network Reliability Assessment UE PL 2304	5.5.1 to 5.5.5
RRP 5-4a	– Automatic Circuit Reclosers (ACRs) and Remote Control Gas Switches (RCGSs)	5.5.7
RRP 5-4b	– Fuse Savers – spreadsheet	5.5.7
RRP 5-4c	– Rogue Feeders - spreadsheet	5.5.7
RRP 5-4d	– Clashing - spreadsheet	5.5.7
RRP 5-4e	– Animal Proofing - spreadsheet	5.5.7
RRP 5-4f	– Communications Upgrade - spreadsheet	5.5.7
RRP 5-5	Network Safety Assessment	5.5.1, 5.5.2, 5.5.3, 5.5.4, 5.5.5
RRP 5-6	Bushfire Mitigation ALARP Assessment 2015	5.5.1, 5.5.4
RRP 5-7	Updated Bushfire Mitigation Plan	5.5.7
RRP 5-8	Nuttall Consulting report – AER repex modelling – addendum – consideration of AER preliminary decision – A report to UED, December 2015	5.5.1, 5.5.4, 5.5.5
RRP 5-9	Power Quality Maintained CEES	5.5.1, 5.5.4, 5.5.7
RRP 5-10	Environment CEES	5.5.1, 5.5.4, 5.5.7
RRP 5-11	Terminal Station Redevelopment HTS – UE-DOA-S-17-002	5.5.1, 5.5.4, 5.5.7

Document reference	Document name	RRP sub-section reference
RRP5-11a	– HTS UE-DOA-S-17-002 – spreadsheet	
RRP 5-12	Terminal Station Redevelopment RTS – UEDO-14-003	5.5.1, 5.5.4, 5.5.7
RRP 5-12a	– RTS – UEDO-14-003 – spreadsheet	5.5.1, 5.5.4, 5.5.7
RRP 5-13	Intelligent Secure Substation Asset Management (ISSAM) (CCTV) UE PL 2401 - **Confidential**	5.5.3, 5.5.4, 5.5.7
RRP 5-14	Service Mains Deterioration Field Works PJ1385	5.5.3, 5.5.4, 5.5.7
RRP 5-14a	Service Mains Deterioration Field Works – PJ1385 spreadsheet	5.5.3, 5.5.4, 5.5.7
RRP 5-15	In Meter Capabilities (IMC) PJ1386	5.5.3, 5.5.4, 5.5.7
RRP 5-15a	– IMC PJ1386 – spreadsheet	5.5.3, 5.5.4, 5.5.7
RRP 5-16	Light Detection And Ranging (LiDAR) Asset Management PJ1400	5.5.3, 5.5.4, 5.5.7
RRP 5-16a	LiDAR PJ1400 spreadsheet	5.5.3, 5.5.4, 5.5.7
RRP 5-17	Dynamic Rating Monitoring Control Communication (DRMCC) PJ1413	5.5.3, 5.5.4, 5.5.7
RRP 5-17a	– DRMCC – PJ1413 spreadsheet	5.5.3, 5.5.4, 5.5.7
RRP 5-18	Updated Zone Substation Capacitor Banks, Earth Grids, Neutral Earth Resistor, Transformer Instrumentation – CEES	5.5.3, 5.5.4, 5.5.7
RRP 5-19	Updated Zone Substation Buildings CEES	5.5.3, 5.5.4, 5.5.7
RRP 5-20	HV Aerial Bundled Cable Strategic Analysis Plan – UE PL 2053	5.5.3, 5.5.4, 5.5.7, 5.5.8
RRP 5-20a	– HV ABC – UE PL 2053 – spreadsheet	5.5.3, 5.5.4, 5.5.7, 5.5.8
RRP 5-20b	– ESV letter re HV ABC replacement	5.5.3, 5.5.4, 5.5.7, 5.5.8
RRP 5-20c	– HV ABC media reports	5.5.3, 5.5.4, 5.5.7, 5.5.8
RRP 5.21	DMA and MTN ZSS REFCL Installation	5.5.3, 5.5.4, 5.5.7, 5.5.8
RRP 5-22	OT Security PJ1500 – **Confidential**	5.5.4, 5.5.7
RRP 5-23	Distribution Fault Anticipation Data Collection and Analytics (DFADCAA) PJ1599	5.5.4, 5.5.7
RRP 5-23a	– DFADCAA PJ1599 – spreadsheet	5.5.4, 5.5.7

Document reference	Document name	RRP sub-section reference
RRP 5-24	Fault Location Identification and Application Development (FLIAD) PJ1600	5.5.4, 5.5.7
RRP 5-24a	– FLIAD PJ1600 – spreadsheet	5.5.4, 5.5.7
RRP 5-25	Test Harness PJ1398	5.5.4, 5.5.7
RRP 5-25a	– Test Harness PJ1398 – spreadsheet	5.5.4, 5.5.7
RRP 5-26	Pilot New and Innovative Technologies PJ1407	5.5.4, 5.5.7
RRP 5-26a	– Pilot Technologies PJ1407	5.5.4, 5.5.7
RRP 5-27	DNSP Intelligent Network Device PJ5002	5.5.4, 5.5.7
RRP 5-27a	– DNSP Intelligent Network Device PJ5002	5.5.4, 5.5.7
RRP 5-28	Repex and Opex to Maintain Reliability	5.5
RRP 5-29	Repex and Opex Initiatives to Manage Network Safety	5.5
RRP 5-30	CA RIN Other Un-modelled corrected	5.5.1
ICT		
RRP 5-31	PoC Consumer Data Access (PJ15)	5.6, Appendix E
RRP 5-32	PoC Customer Switching (PJ16)	5.6, Appendix E
RRP 5-33	PoC Demand Response Mechanism (PJ18)	5.6, Appendix E
RRP 5-34	PoC Metering Competition (PJ19)	5.6, Appendix E, Appendix F
RRP 5-35	PoC Network Pricing (PJ21)	5.6, Appendix E
RRP 5-36	PoC Demand Management AEMO Reporting (PJ25)	5.6, Appendix E, Appendix F
RRP 5-37	PoC Demand Management IT Platform (PJ26)	5.6, Appendix E, Appendix F
RRP 5-38	PoC Embedded Networks (PJ27)	5.6, Appendix E
RRP 5-39	RIN Reporting (PJ22 - RIN)	5.6, Appendix E
Opex		
RRP 6 -1	**Confidential** letter dated 2 December 2015 from UE to the AER (2011-15 efficiency carryover calculation)	6.4.2 and 10.1.2
Regulatory asset base and depreciation		
RRP 7-1	UE Sunk Depreciation	7.2 and 7.3

Document reference	Document name	RRP sub-section reference
Rate of Return		
RRP 8 -1	**Confidential** letter to AER dated 6 January 2016 from UE to AER nominating debt averaging periods	8.3
RRP 8-2	Response to AER Preliminary Determination – Re: Rate of Return and Gamma	8.1 to 8.7 and 9.2
RRP 8-3	The required return on equity under a foundation model approach, Frontier	8.2 and 8.4
RRP 8-4	The relationship between government bond yields and the market risk premium, Frontier	8.2 and 8.4
RRP 8-5	CGS Yields and MRP, Frontier	
RRP 8-6	The appropriate use of tax statistics when estimating gamma, Frontier	8.2 and 8.6
RRP 8-7	The Cost of Equity: Response to the AER's Draft Decisions for the Victorian Distributors (Response to Partington and Satchell), Houston Kemp	8.2 and 8.4
RRP 8-8	Critique of the AER's approach to transition, CEG	8.2 and 8.3
RRP 8-9	Criteria for assessing fair value curves, CEG	8.3
RRP 8-10	Measuring expected inflation for the PTRM, CEG (RRP 8-13)	8.3 and 8.7
RRP 8-11	Critique of AER analysis of New Issue Premium, CEG	8.3
RRP 8-12	Cost of Debt - Estimating the yield on a benchmark corporate Nov/Dec 2015: Analysis to support the hybrid form of the transition to a trailing average rate of return on debt, Esquant	8.3
RRP 8-12a	T Reuters BBB Rating AUD Credit Curve BMK, Esquant	8.3
RRP 8-12b	TR BBB Credit Curve – workbook, Esquant	8.3
RRP 8-13	Detailed supporting documents - Frontier	8
RRP 8-14	Detailed supporting documents – Houston-Kemp	8
Certifications		
RRP 18-1	Directors and CEO Certifications	18
Appendices		

Document reference	Document name	RRP sub-section reference
Appendix F - 1	Energy Safe Victoria (ESV) Guidance Information on The new Electricity Safety (Electric Line Clearance) Regulations 2015 dated 27 November 2015	Appendix F - Step change 3.b

Appendix A – Cordell major project list

Table A-1: Recoverable Works (CR) future projects

Project_Name	Suburb	Value ($M)	Category	State	Start_Date	end_date	cordell_ project id
MCKINNON ROAD RAIL LEVEL CROSSING REMOVAL	MCKINNON	130	Roads	VIC	07/12/2015	30/07/2017	2061950
CLAYTON ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	CLAYTON	150	Roads	VIC	01/02/2016	30/06/2018	2087652
POATH ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	MURRUMBEE NA	150	Roads	VIC	01/02/2016	30/06/2018	1905773
HEATHERTON ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	NOBLE PARK	150	Roads	VIC	01/02/2016	30/06/2018	1906062
CHANDLER ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	NOBLE PARK	150	Roads	VIC	01/02/2016	30/06/2018	1906069
KOORNANG ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	CARNEGIE	150	Roads	VIC	01/02/2016	30/06/2018	2088070
HEATHERDALE ROAD MITCHAM LEVEL CROSSING REMOVAL	MITCHAM	120	Roads	VIC	07/12/2015	30/12/2017	2103941
GRANGE ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	CARNEGIE	150	Roads	VIC	01/02/2016	30/06/2018	1906003
CENTRE ROAD BENTLEIGH LEVEL CROSSING REMOVAL	BENTLEIGH	100	Roads	VIC	07/12/2015	30/06/2017	2060761
THOMPSONS ROAD DUPLICATION	LYNDHURST	30	Roads	VIC	01/01/2019	30/12/2020	1620735
BURKE ROAD RAIL LEVEL CROSSING REMOVAL	GLEN IRIS	130	Roads	VIC	08/06/2015	30/06/2016	1763401
MORDIALLOC BYPASS	ASPENDALE GARDENS	20	Roads	VIC	02/07/2018	26/07/2019	1765975

Project_Name	Suburb	Value ($M)	Category	State	Start_Date	end_date	cordell_ project id
MURRUMBEENA ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	MURRUMBEENA	150	Roads	VIC	01/02/2016	30/06/2018	2088093
WESTALL ROAD EXTENSION	SPRINGVALE	20	Roads	VIC	07/12/2015	09/06/2017	1933038
BLACKBURN ROAD RAIL LEVEL CROSSING REMOVAL	BLACKBURN	120	Roads	VIC	07/12/2015	29/12/2017	1616433
CENTRE ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	CLAYTON	150	Roads	VIC	01/02/2016	30/06/2018	1905537
CORRIGAN ROAD RAIL LEVEL CROSSING REMOVAL - CAULFIELD TO DANDENONG PACKAGE	NOBLE PARK	150	Roads	VIC	01/02/2016	30/06/2018	1906051

Table A-2: Business Supply (CB) future projects

Project_Name	Suburb	Value ($M)	Category	State	Start_Date	end_date	cordell_ projectid
GARDENHILL APARTMENTS	DONCASTER	30	Residential	VIC	17/08/2015	13/01/2017	932458
FRASER ROAD TRANSFER STATION	CLAYTON SOUTH	50	Industrial	VIC	15/02/2016	17/12/2016	2095762
JUNCTION OVAL VICTORIAN CRICKET AND COMMUNITY CENTRE	ST KILDA	40	Entertainment and Recreation	VIC	04/01/2016	30/06/2017	1440303
PANORAMA APARTMENTS	DONCASTER	50	Residential	VIC	12/01/2015	02/12/2016	1658035
CITY EDGE APARTMENTS	BOX HILL	27	Residential	VIC	06/04/2015	14/10/2016	1591225
HOLMES HILL APARTMENTS	CHADSTONE	38	Residential	VIC	17/08/2015	23/12/2016	1765277
THE STANDARD	BRIGHTON	27	Residential	VIC	12/01/2015	02/09/2016	1853947
DEAKIN UNIVERSITY BUILDING MC STUDENT ACCOMMODATION	BURWOOD	50	Education	VIC	14/09/2015	03/03/2017	2124469
HOLMESGLEN PRIVATE HOSPITAL	MOORABBIN	100	Health and Aged Care	VIC	06/07/2015	23/12/2016	1963258

ANZ DATA CENTRE	MOUNT WAVERLEY	24	Other Commercial	VIC	09/02/2015	12/02/2016	1950022
THE NOVA CENTRE	CLAYTON	250	Residential	VIC	11/05/2015	23/12/2016	25412
QUEST APARTMENTS DANDENONG	DANDENONG	25	Accommodatio n	VIC	07/03/2015	25/03/2016	1789377
WEEROONA AGED CARE FACILITY	MALVERN EAST	30	Health and Aged Care	VIC	12/01/2015	27/03/2016	739652
PRESBYTERIAN LADIES COLLEGE (PLC) PERFORMING ARTS CENTRE	BURWOOD	28	Education	VIC	28/05/2015	18/11/2016	1983524
MAGNOLIA APARTMENTS	DONCASTER	24	Residential	VIC	20/04/2015	23/12/2016	1445497
BUNURONG MEMORIAL PARK	DANDENONG SOUTH	40	Miscellaneous	VIC	13/01/2015	18/12/2015	1767090
HMAS CERBERUS AND WEST HEAD GUNNERY RANGE HAZARDOUS AREA CLASSIFICATIONS	FLINDERS	88	Miscellaneous	VIC	02/03/2015	03/04/2015	2038882
THE EASTON	BURWOOD	32	Residential	VIC	27/07/2015	09/12/2016	1046959
ILIXIR APARTMENTS	CHELTENHA M	25	Residential	VIC	14/09/2015	31/03/2017	1818060
REVITALISING CENTRAL DANDENONG PRECINCT LAND DEVELOPMENT	DANDENONG	20	Residential	VIC	03/10/2016	03/10/2018	2114355

Appendix B – Examples of projects included in 2015 unit rate calculations but omitted from 2014 unit rate calculation

Project WBS89	Three-letter code	Date the SoW received	Customer contribution	Actual Cost in FY14	Actual cost in FY15	Total project cost[90]	Status end of FY 2015[91]	Status end of FY 2014
UED-COM-006140	CRS	APR 2014	100%	24,849	292	25,141	RFCL CFWD	REL
UED-COM-004863	CRU	01/08/2013	100%	77,187	34,043	111,229	RFCL CFWD	REL
UED-COM-005638	CRU	AUG 2014	86%	9,380	135,051	144,431	UEAT CFWD	REL
UED-COM-000563	CRA	01/06/2013	98%	401,490	11,325	412,815	PCRD CFWD	TECO
UED-COM-003894	CRA	01/02/2013	87%	167,361	4,119	171,480	RFCL CFWD	REL
UED-COM-006425	CRA	01/03/2014	100%	168,155	14,892	183,047	RFCL CFWD	REL
UED-COM-003864	CBK	01/08/2013	22%	152,353	113,916	266,268	RFCL CFWD	REL
UED-COM-001114	CBK	01/02/2012	19%	234,576	11,466	246,043	RFCL CFWD	REL
UED-COM-003726	CBI	01/03/2013	32%	132,068	8,152	140,220	RFCL CFWD	REL
UED-COM-002643	CBI	01/09/2012	44%	237,237	6,387	243,624	RFCL CFWD	REL
UED-COM-003935	CBP	DEC 2013	50%	57,630	97,664	155,294	UEAB CFWD	REL
UED-COM-004161	CBP	FEB 2014	78%	72,891	39,232	112,123	RFCL CFWD	REL
UED-COM-003886	CBP	OCT 2013	16%	111,755	7,013	118,768	UEAB CFWD	REL

[89] WBS is provided for AER purpose to verify the examples in unit rate analysis modules for 2014 and 2015

[90] Total project cost realised in 2015 rather in 2014 due to deferral

[91] CFWD: carry forward to next FY, RFCL: ready for closing, REL: released/initiated, etc.

Appendix C – Reliability Assessment – AER and UE Comparison

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11 December 2015

Mr Chris Pattas
General Manager Networks
Australian Energy Regulator
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Melbourne VIC 3000

Email: chris.pattas@aer.gov.au

Dear Chris

Re: Meeting with UE and ESV on 30 November 2015 – Network Safety and Reliability

1. Introduction

Thank you for meeting with us and Energy Safe Victoria (ESV) on 30 November 2015 to discuss:

(1) The changes to the *Electricity Safety (Electric Line Clearance) Regulation 2015,* which were finalised on 28 June 2015, and their impact on us in the 2016 to 2020 period; and

(2) Our reliability and safety performance over the current 2011 to 2015 period and the implications of this for our capex requirements in the 2016 to 2020 period.

We will address our concerns with the AER's Preliminary Decision on both of these matters in our Revised Regulatory Proposal, which we will provide to the AER by 6 January 2016. However, as foreshadowed at our meeting, we have provided an early outline of our concerns in relation to issue (2) for the AER's consideration prior to receiving our Revised Regulatory Proposal. In particular, we set out our concerns with the following three matters:

(i) Deterioration in our SAIFI performance;

(ii) Deterioration in our CAIDI performance and its correlation to the industry trend; and

(iii) Our future Repex requirements to address our deteriorating reliability performance.

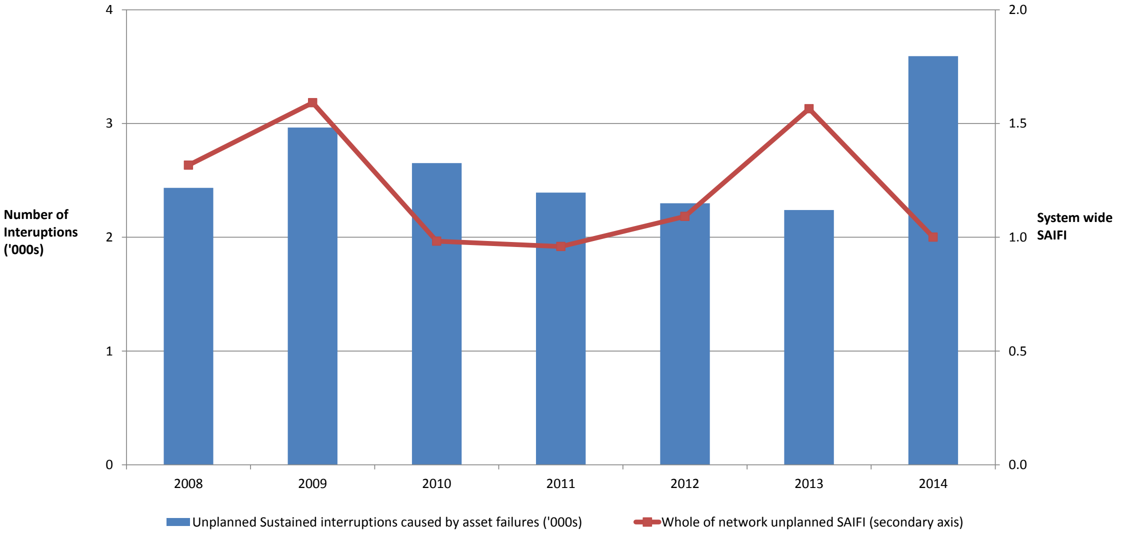
Please see footnoted[92] a link to the ESV's "*Safety Performance Report on Victorian Electricity Networks 2014"* that we referred to during the meeting. The ESV's report highlights the deterioration in our safety performance as measured by a range of safety metrics such as fires per kilometre of overhead line and conductor failures.

2. Deterioration in our SAIFI performance

In its Preliminary Decision, the AER stated that "*Figure 6.15 shows that United Energy's outages due to asset failures and SAIFI have on average been flat across time. The overall stability in both of these measures indicates that the replacement practices from the last period have been sufficient to meet the capex objectives".*

[92] Found at: http://www.esv.vic.gov.au/Portals/0/about%20esv/FINAL%202014%20Safety%20Performance%20Report%20on%20Victorian%20Electricity%20Networks.pdf

Figure 1: Figure 6-15 from the AER Preliminary Decision - Relationship between system wide SAIFI and non-excluded interruptions caused by asset failures



Relying on Figure 6-15, the AER rejected our arguments that our reliability performance has deteriorated over the 2011 to 2015 period and that our current levels of Repex have not been sufficient to meet our STPIS targets. Figure 6-15 is therefore a key element in the AER's Preliminary Decision, and was critical to the AER rejecting our proposed forecast of $585 million.

We are concerned the data relied on by the AER to derive Figure 6-15 is incorrect and therefore that its decisions based on this figure are also incorrect. We understand that Figure 6-15 has been derived using data from the:

- Economic Benchmarking (EB) RIN - sheet 3.6 "Quality of Services". In particular, the "whole of network unplanned SAIFI" data. The SAIFI data includes MED exemptions and applies the 2006-10 exemption criteria for the 2008-2010 period, and therefore does not reflect the underlying performance of the network; and
- 2013 Category Analysis (CA) RIN - sheet 6.3 "Sustained Interruptions".

For the reasons set out below, we strongly encourage the AER to revise its analysis to incorporate the correct SAIFI and asset failure data and to review its decision on our required Repex for the forthcoming period.

SAIFI Data

We consider that rather than relying on the data sets outlined above, the AER should use SAIFI data set out in Table 1 below. This is consistent with the time series data that was the basis of our responses to the AER's information requests 19 and 26 (denoted as IR#19 and IR#26). This data set applies the current exemption criteria to years prior to 2011 and then excludes MED exemptions, so that all years are compared on a consistent basis.

Table 1: SAIFI performance from 2008 to 2014

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SAIFI	0.92	0.94	0.97	1.02	0.97	1.28	0.96	0.96	1.09	1.01	1.00
SAIFI Asset Failure	0.31	0.33	0.39	0.40	0.46	0.53	0.36	0.27	0.40	0.42	0.41

Source IR #19 Q1 Time Series

This data is presented in Figure 2 and Figure 3 below. Both total SAIFI and equipment failure SAIFI demonstrate an upward trend consistent with our deteriorating reliability performance.

Figure 2: Total SAIFI

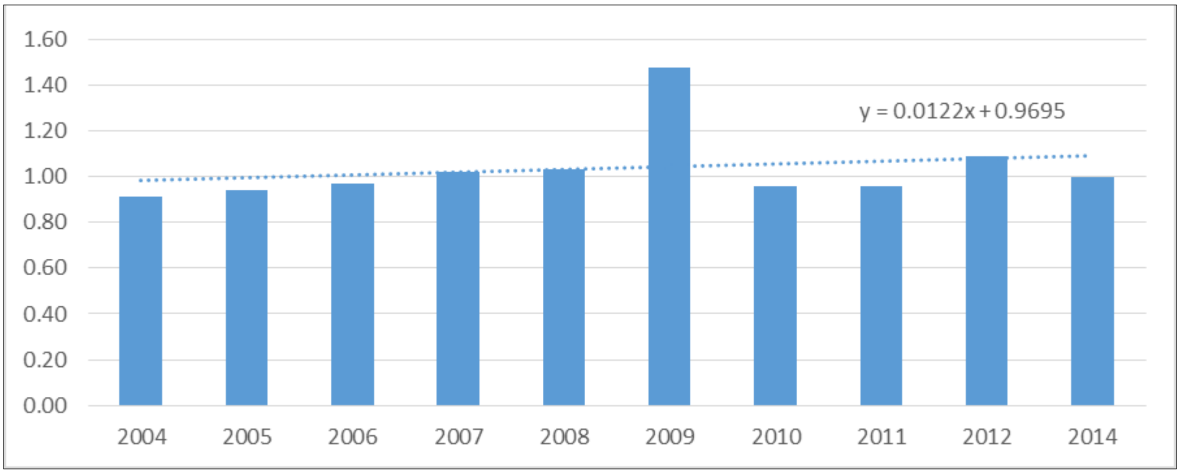
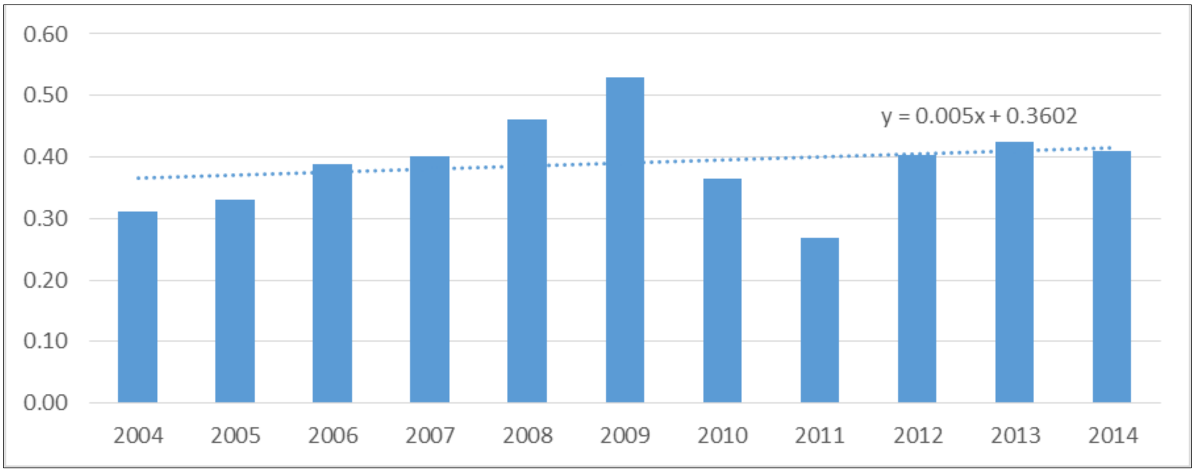


Figure 3: Asset Failure SAIF



Equipment failure data

The data provided in the CA RIN was formulated based on a new cause code system unique to the CA RIN template. We have identified that some of the mapping from the primary cause in our outage database to the CA RIN was carried out incorrectly resulting in five primary causes failing to be classed as equipment failure. The time series submitted as part of IR request #19 Question 1 correctly maps these primary case codes.

The difference in categorisation is shown in Table 2 below:

Table 2: Change in categorisation of outage data

Primary Cause	2008-2013 - CA RIN	2014 CA RIN and IR #19 Time Series
Elements – Deterioration	Weather	Equipment failure
Elements – Pollution (Dust/Salt)	Weather	Equipment failure
Fire – Other or External Fire	Third party	Equipment failure
Other – Electrical Overload	Overloads	Equipment failure

Primary Cause	2008-2013 - CA RIN	2014 CA RIN and IR #19 Time Series
ZS Protection – Protection Mal-operation	Network business	Equipment failure

We have re-categorised the 2008 – 2013 (originally provided in the 2013 CA RIN) on the same basis as that 2014 CA RIN and times series data (as per IR #19). This is reflected in Table 3.

Table 3: Equipment failure data

Year	2008	2009	2010	2011	2012	2013	2014
Equipment Failure HV	283	315	274	211	348	315	383
Equipment Failure LV	4,003	4,294	4,337	3,852	3,642	3,541	3,781
Equipment Failure	4,286	4,609	4,611	4,063	3,990	3,856	4,164

Source - IR #19 Q1 Time Series

The equipment failures most relevant to network reliability are HV and Sub-transmission asset failures, as they result in widespread customer outages. HV and sub-transmission asset failures are 7 per cent of all equipment failure but account for 89 per cent of equipment failure SAIFI.

Conversely, LV and other asset failures are 93% of all equipment failure, but account for only 11 per cent of equipment failure SAIFI, as they affect very few customers in comparison. Given LV and other asset failures have very little impact on network reliability, we consider that trends in reliability from asset failure statistics should exclude LV and other asset failures and be based only on HV and sub-transmission asset failures. Figure 4 below shows our SAIFI performance based on HV and sub-transmission asset failures.

Figure 4: UE's SAIFI calculated based on HV and Sub-transmission asset failures

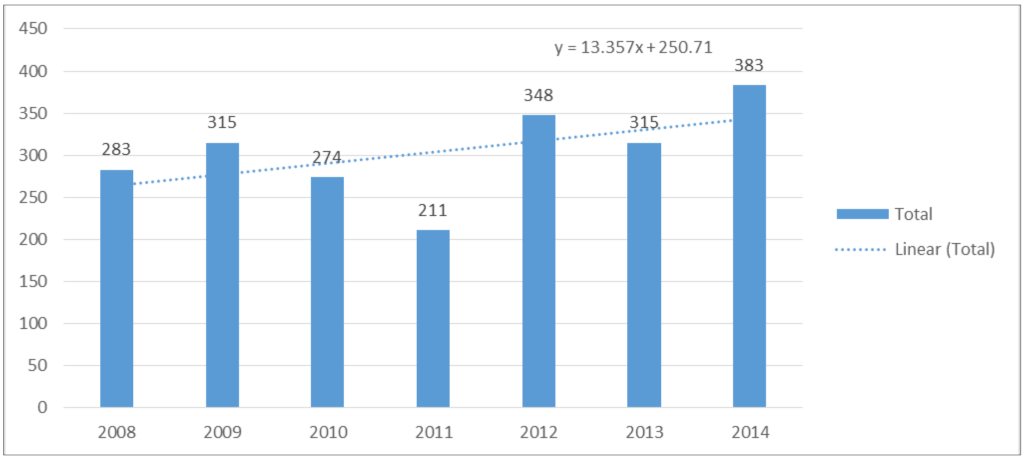


Figure 4 demonstrates that sustained HV and sub-transmission equipment failure is increasing at a rate of approximately 5 per cent per annum. This rate increases to nearly 10 per cent per annum if the data series commences in 2004. The increasing HV and sub-transmission equipment failure rate is consistent with our increasing network wide SAIFI.

In its Preliminary Decision, the AER concludes that our Repex levels in the current period are sufficient to allow us to meet our reliability objective. The AER has largely based its decision on the SAIFI and asset failure data presented in Figure 6.15 of its Preliminary Decision.

We request the AER revise its analysis to incorporate the correct SAIFI and asset failure data sets for the reasons set out above.

3. Deterioration in our CAIDI performance and its correlation to industry trend

At the meeting, we highlighted that our CAIDI has deteriorated, consistent with the industry trend. The AER indicated, however, that its analysis showed no deterioration in industry CAIDI.

To assist the AER, we set out below our analysis showing a deterioration in industry CAIDI. We have based our analysis on publically available RIN data which we consider is the most appropriate data available.

Our CAIDI for days that contribute to STPIS shows a deterioration of 5.5 minutes per annum compared to the Victorian average (excluding United Energy) of 2.6 minutes per annum, over the period 2008 to 2014.

Table 4: CAIDI – Exclusions and MEDs removed – Victorian Average (exc. UE) versus UE

CAIDI - Exclusions & MEDs Removed	2008	2009	2010	2011	2012	2013	2014
Victorian Average (excluding United Energy)	60.20	72.65	72.09	71.27	71.71	72.25	84.62
United Energy	48.02	47.26	58.53	63.54	72.48	73.10	77.91
Source	2006-13 EB RIN	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN

Figure 5: UE's – CAIDI – Exclusions and MEDs removed

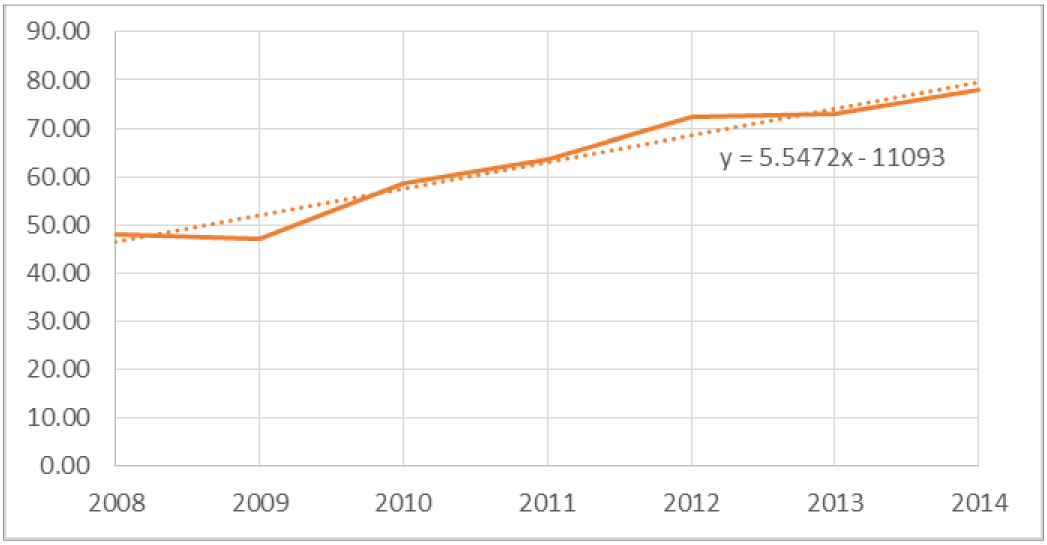
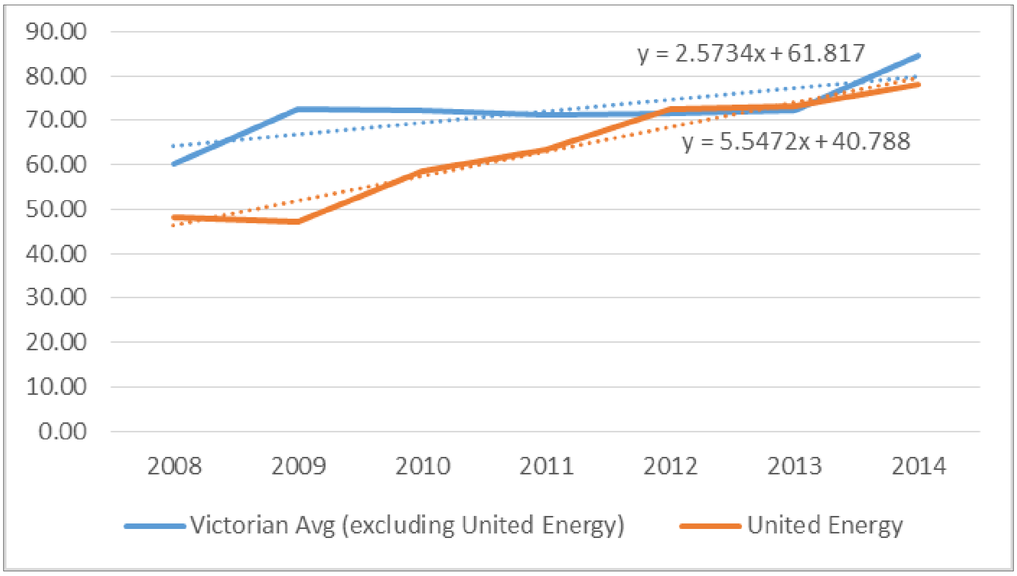


Figure 6: CAIDI – Exclusions and MEDs removed – Victorian Ave (exc. UE) versus UE



When our CAIDI performance is assessed over a longer time period it can be seen that our deterioration in performance is slower at 2.2 minutes per annum, and equates to a 40 per cent increase over 10 years. This is shown in Figure 7 below.

Figure 7: UE CAIDI – Trend versus actual

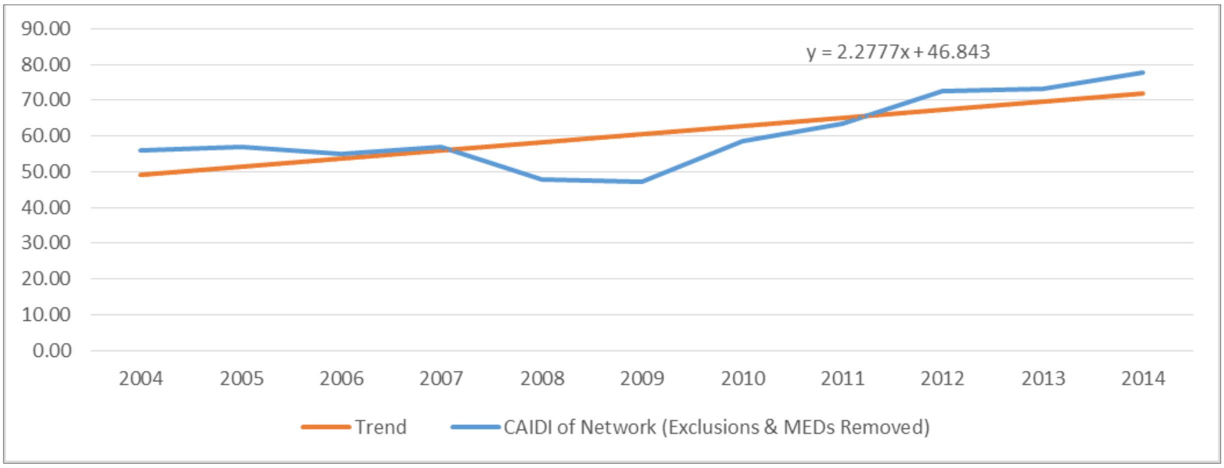


Table 5: UE CAIDI – Trend versus actual

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAIDI of Network (Exclusions & MEDs Removed)	56.00	56.99	54.92	56.85	48.02	47.26	58.53	63.54	72.48	73.10	77.91
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN

Figure 8 below shows that when the assessment is extended to the national level it can be seen that the average CAIDI is also increasing across Australia by 1.0 minutes per annum.

Figure 8: CAIDI – Exclusions and MEDs removed – Australian Average (exc. UE) versus UE

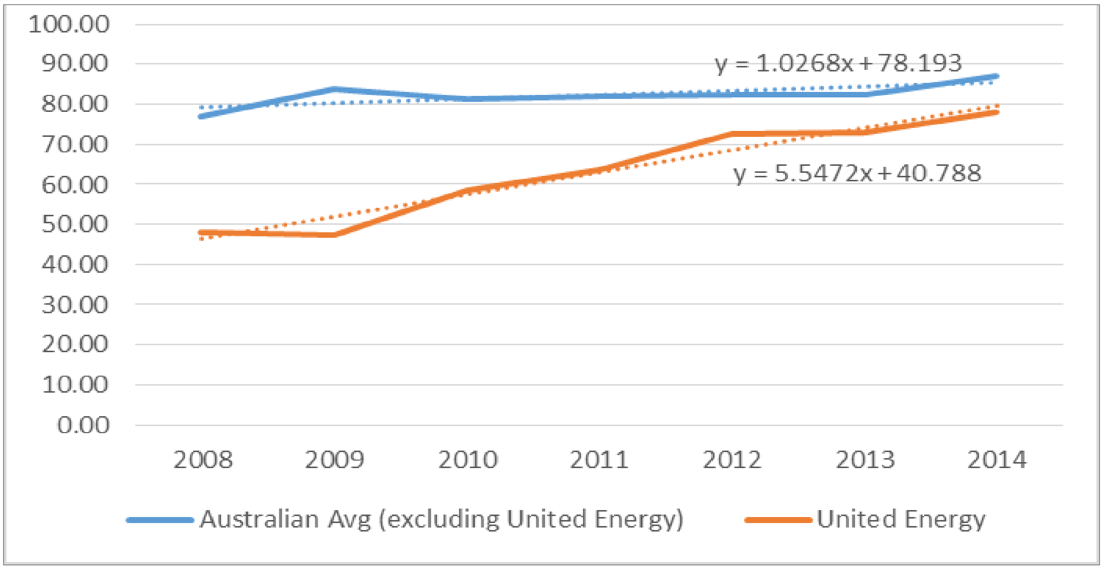


Table 6: Exclusions and MEDs removed – Australian Average (exc. UE) versus UE

CAIDI - Exclusions & MEDs Removed	2008	2009	2010	2011	2012	2013	2014
Australian Average (excluding United Energy)	77.13	83.71	81.24	82.08	82.26	82.55	87.14
United Energy	48.02	47.26	58.53	63.54	72.48	73.10	77.91
Source	2006-13 EB RIN	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN

The CAIDI for each DNSP has been calculated from the SAIDI and SAIFI data submitted to the AER. The sources for the SAIDI and SAIFI data depended on the distribution network and the year. The list of sources used, in order of priority are:

- Reset Regulatory Information Notices (RINs) – AER website;
- Annual Non-Financial RINs – AER website; and
- Economic Benchmarking RINs – AER website.

The average CAIDI performance, both for Victoria and nationally, has been calculated as a simple average and thereby weights each business equally. Our performance has been excluded from both averages. Noting that the larger DNSPs have a rate of increase higher than the Australian average, using an average weighted on say the number of customers would yield a high rate of CAIDI increase at the national level.

The data and trend for each Australian DNSP is presented in Attachment A. The source of the data for each DSNP for each year has been identified. The analysis shows that CAIDI is increasing for 10 of the 13 Australian DNSPs.

We believe the RIN data we have used for this analysis is the most appropriate data available. This analysis demonstrates a clear industry trend of increasing CAIDI. We are unable to fathom how the AER has not arrived at the same conclusion.

Note that our CAIDI deterioration is predominately driven by:

- Reductions in traffic flow speeds which means our response crews take longer to reach site.
- Increasing number of HV events, which typically take longer to repair than faults on the LV network
- Increasing number of HV simultaneous events, and a shortage of resources; and
- Increasing percentage of faults caused by equipment failure which take longer to repair.

4. The application of UE Repex to address our deteriorating reliability performance

We are concerned that our approach to populating the CA and Reset RINs has led the AER to misinterpret and therefore incorrectly assess components of our 2016 to 2020 Repex forecast. We have reported significant expenditure as "Other Repex", whereas we see that other DNSPs have categorised this type of expenditure as Augmentation capex (Augex).

Our "Other Repex" category of expenditure is designed to address reliability, safety, power quality and environmental requirements. This investment involves maintenance of the network (as opposed to network augmentation) and therefore we consider that this investment should be properly categorised as Repex.

As presented in the AER's Preliminary Decision, our Repex submission can be classified as follows:

(1) Asset Replacement (modelled – 6 categories), plus pole top replacement and SCADA/protection and control replacement

(2) VBRC Safety

(3) "Other Repex", including

   a. Maintain Reliability Projects

   b. Safety (non VBRC)

   c. Environment

   d. Power Quality

   e. Operational Technology

   f. Asset replacement of zone substation other primary plant (excludes transformers and switchgear, includes capacitor banks, neutral earthing resistors, earthing, buildings)

Expenditure categorised as (3)(a) to (e), is not concerned with replacing assets, as suggested by the AER on page 6-81 of its Preliminary Decision:

> *It is unclear why the need to replace these assets has suddenly and significantly arisen in the forthcoming period.*

Rather, this expenditure is for additional assets associated with maintaining reliability and safety (as well as power quality and environment). As noted, we see that other DNSPs have categorised this type of expenditure as "Other Augex, not related to Demand".

In our Revised Regulatory Proposal, we propose to:

- Leave this expenditure in "Other Repex" and adopt the classification presented by the AER in its Preliminary Decision in order to minimise any further confusion;
- Address the issues raised by the AER in its Preliminary Decision and submit revised business cases that include more robust options analysis and cost benefit analysis;
- Clarify that expenditure for "Other Repex" for the 2011-2015 period is $43 million and not $28 million as asserted by the AER.

In considering the impact of capex on network reliability, it is helpful to break down reliability into its primary components, as follows:

(i) SAIFI:

   a. Equipment failure fault frequency;

b. Non-equipment failure fault frequency; and

c. Number of customers impacted by faults.

(ii) CAIDI – restoration times.

(Noting that SAIDI is a combination of SAIFI and CAIDI).

Each component of our Repex contributes to maintaining network reliability as follows:

Category of Repex	Contribution to maintaining network reliability
(1) Asset Replacement (6 categories modelled + pole top + SCADA/protection)	Asset replacement specifically addresses the "equipment failure fault frequency component of SAIFI" consistent with the AER's general position stated in their preliminary decision.
(2) VBRC Safety	The bulk of these projects are replacement of assets in the overhead conductor category, and in our reliability assessment they are classified in this way. Thus, this repex category also address the "equipment failure fault frequency component of SAIFI".
(3) Other Repex	
(a) Maintain Reliability Projects	Some projects address • The non-equipment failure fault frequency component of SAIFI (e.g. animal proofing); and • The number of customers impacted by a faults (e.g. ACRs and remote control gas switches which allow increased sectionalisation).
(b) Safety (Non VBRC)	No impact on reliability.
(c) Environment	No impact on reliability.
(d) Power Quality	No impact on reliability.
(e) Operational Technology	Some projects address: • Restoration times and hence CAIDI (e.g. fault location identification). • Issues like network safety and therefore have no impact on reliability.
(f) Asset replacement of zone substation primary assets (e.g. capacitor banks, NERs)	Asset replacement specifically addresses the "equipment failure fault frequency component of SAIFI".

We therefore agree with the AER that the asset replacement component of our Repex forecast should specifically address maintaining SAIFI, noting that it can only influence the equipment failure fault frequency component of SAIFI. We confirm this is the approach we have taken.

We also note the AER must allow us sufficient capex to maintain performance at the targets set under the STPIS scheme. On page 6-29 of its Preliminary Decision the AER itself states:

> *The STPIS is interrelated to United Energy's total forecast capex ...... Further, the forecast capex should be sufficient to allow United Energy to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to United Energy systematically under or over performing against its targets.*

As outlined above, a significant component of our "Other Repex" addresses other aspects of reliability that are part of the STPIS targets.

As our current reliability performance is considerably worse than the revised targets to be set for the 2016-20 period, the AER must therefore provide us with sufficient capex to close the gap and meet the revised targets.

Our assessment of how our capex and opex proposal maintains all aspects of reliability (to achieve our STPIS targets for 2016-20) at minimum cost is summarised in the spreadsheet "Reliability Assessment V4.pdf" submitted to the AER 3 September 2015, following a meeting with the AER and Energeia on 2 September. We have now assembled all the documentation from this assessment into UE PL 2304 *Network Reliability Assessment*, which we will submit with our Revised Regulatory Proposal. This presents the ranking and trade-offs we have made, to maintain all aspects reliability at minimum cost.

5. Summary

Overall Reliability

- Over the 2011 to 2015 period, our reliability has deteriorated. This is demonstrated by the significant STPIS penalties we have incurred.
- Notwithstanding this, in its Preliminary Decision, the AER has concluded, primarily on the basis of the SAIFI and asset failure data presented in Figure 6.15 of Preliminary Decision, that our reliability is being maintained.
- Our CAIDI has also been deteriorating, consistent with the industry trend. This is discussed in section 3 above, and is supported by our analysis in Attachment A to this letter.
- The “Other Repex” component of our 2016-2020 Repex forecast includes a significant amount of expenditure classified by other DNSPs as “Other Augex, not addressing Demand”. Some of this proposed investment specifically addresses reliability other than the “equipment failure frequency component of SAIFI”. This expenditure is required to allow us to maintain all aspects of reliability performance and meet our STPIS targets and is discussed in section 4 of this letter.
- For the reasons set out in this letter, we strongly request that in making its Final Decision the AER undertake revised analysis of our reliability performance and Repex requirements using more appropriate datasets for SAIFI and asset failure data as discussed in section 2 of this letter. This will show that our Repex over the current period has been insufficient to allow us to meet our reliability objectives and that the AER should amend its decision on our Repex for the 2016 to 2020 period.

Reliability investment approach

- Our *Network Reliability Assessment* sets out our approach to determining which investments, both capex and opex, are included in our expenditure forecast in order to maintain reliability and therefore achieve our 2016-20 STPIS targets at minimum cost. This will be submitted to the AER together with our Revised Regulatory Proposal.

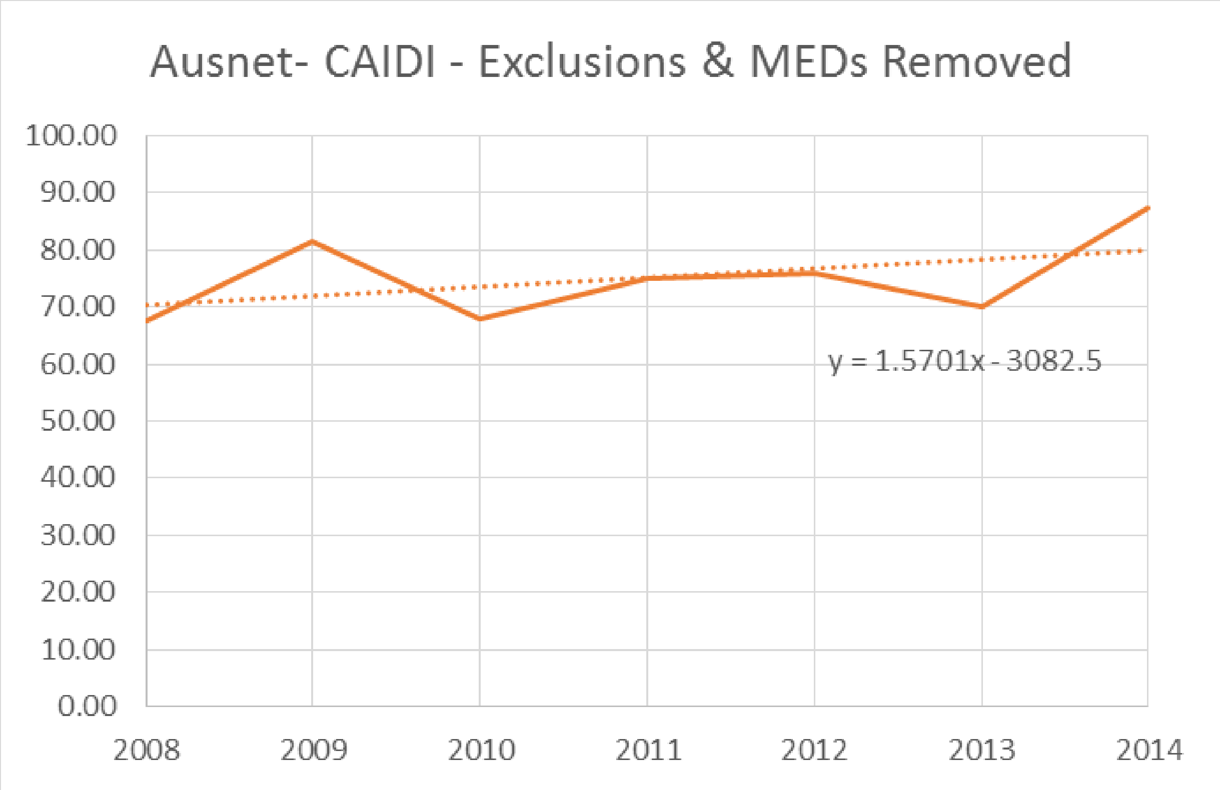
6. Closing

Please do not hesitate to contact me on (03) 8846 9860 or Stephanie McDougall, Price Review Manager on (03) 8846 9538 if you would like to discuss any matters in this letter.

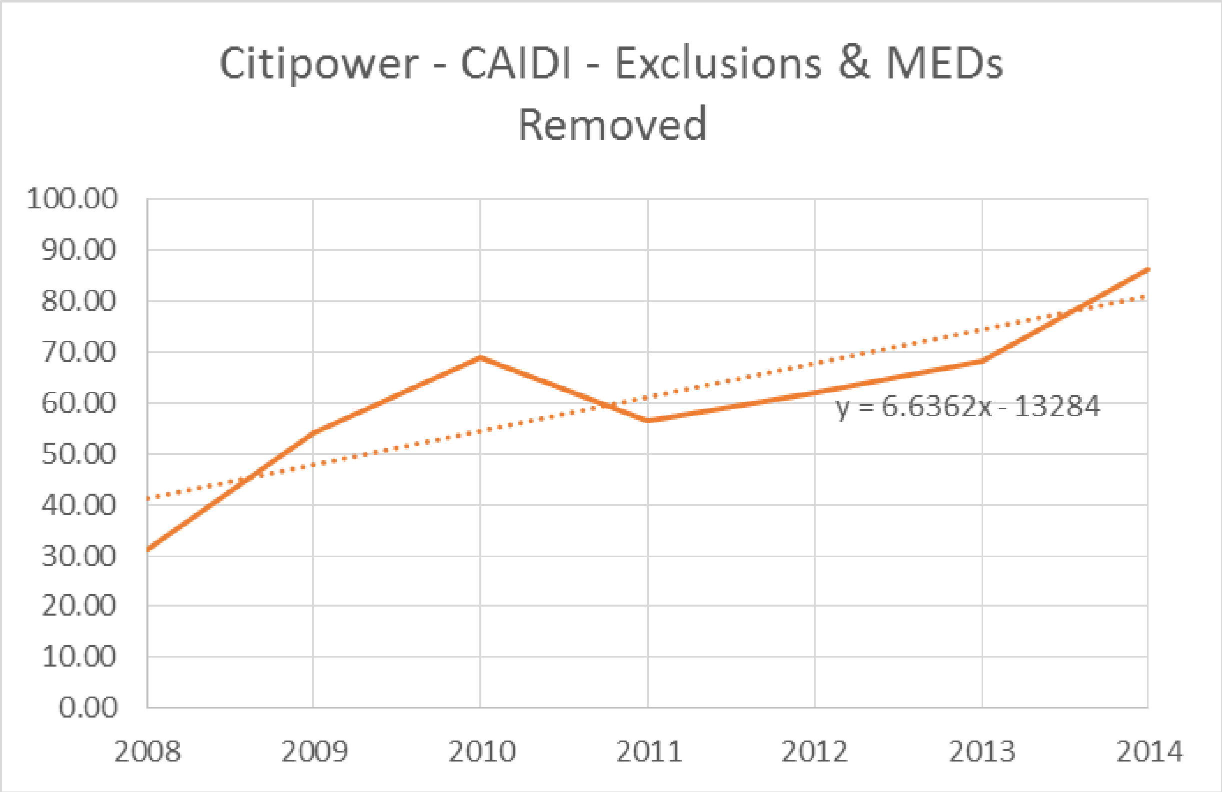
Yours faithfully

Andrew Schille
General Manager, Regulation

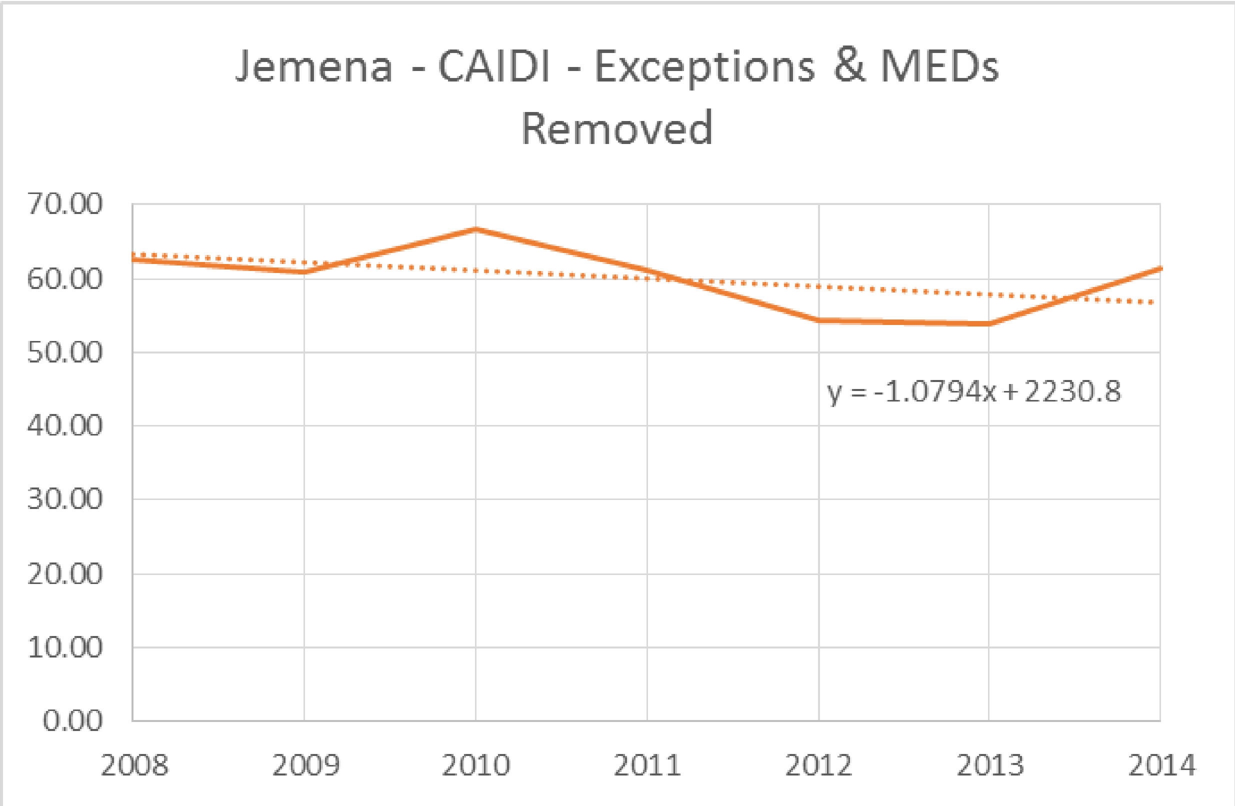
Attachment A – CAIDI for NEM DNSPs



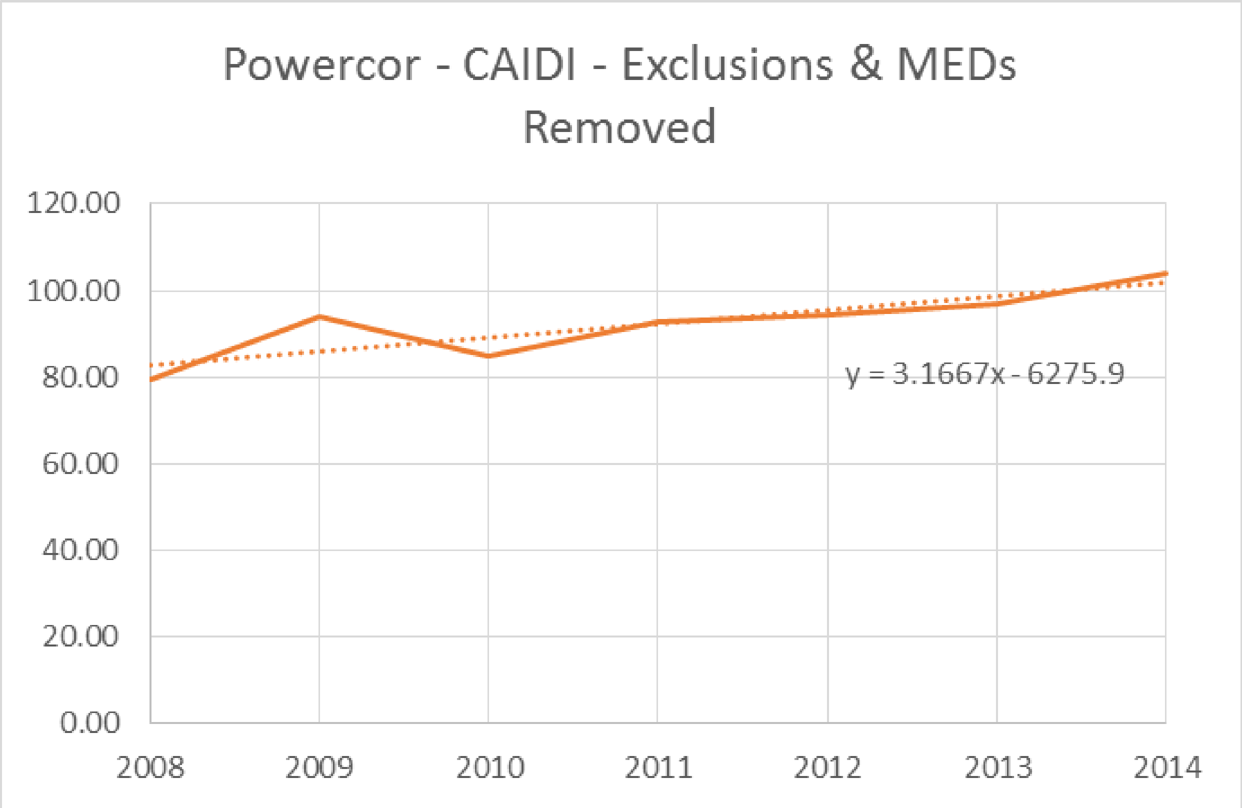
	2008	2009	2010	2011	2012	2012-13	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	67.54	81.56	67.99	74.95	75.89	70.09	87.21
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2012-13 Annual RIN	2013-14 Annual RIN



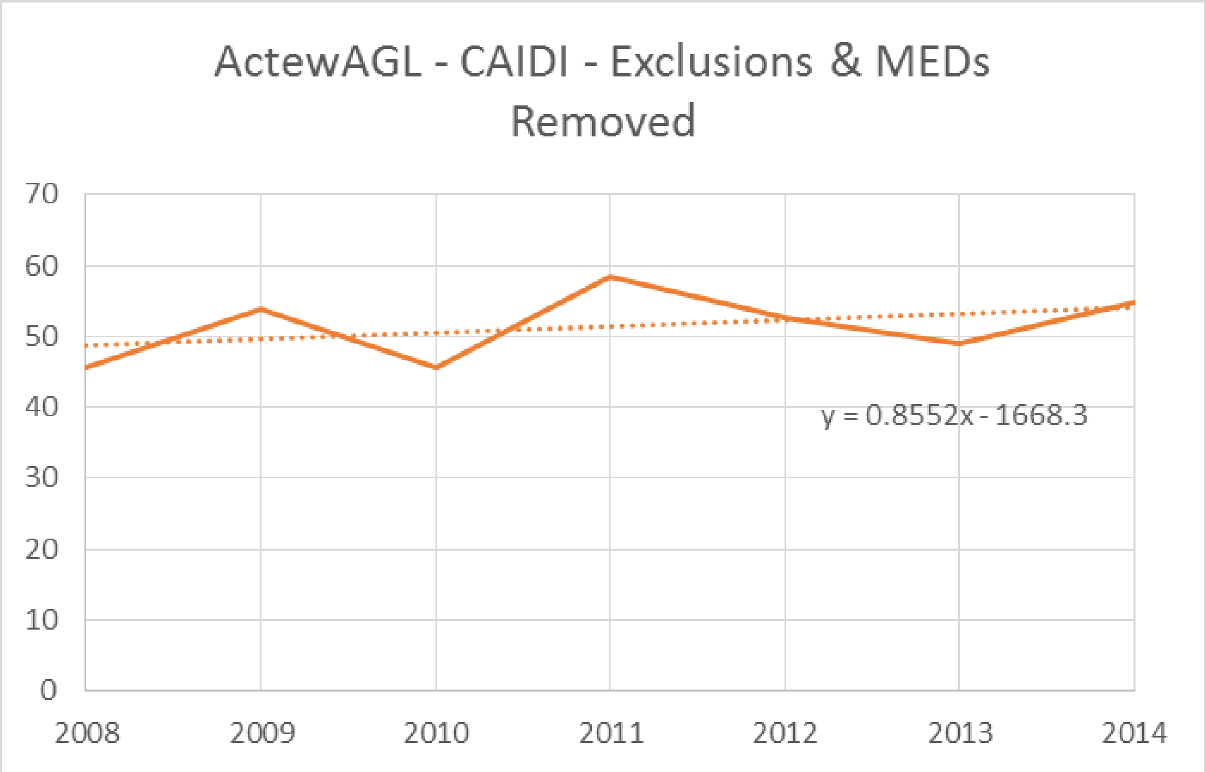
	2008	2009	2010	2011	2012	2013	2014
CAIDI of Network (Exclusions & MEDs Removed)	31.26	54.25	68.90	56.35	62.16	68.25	86.12
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2013 Annual RIN	2014 Annual RIN



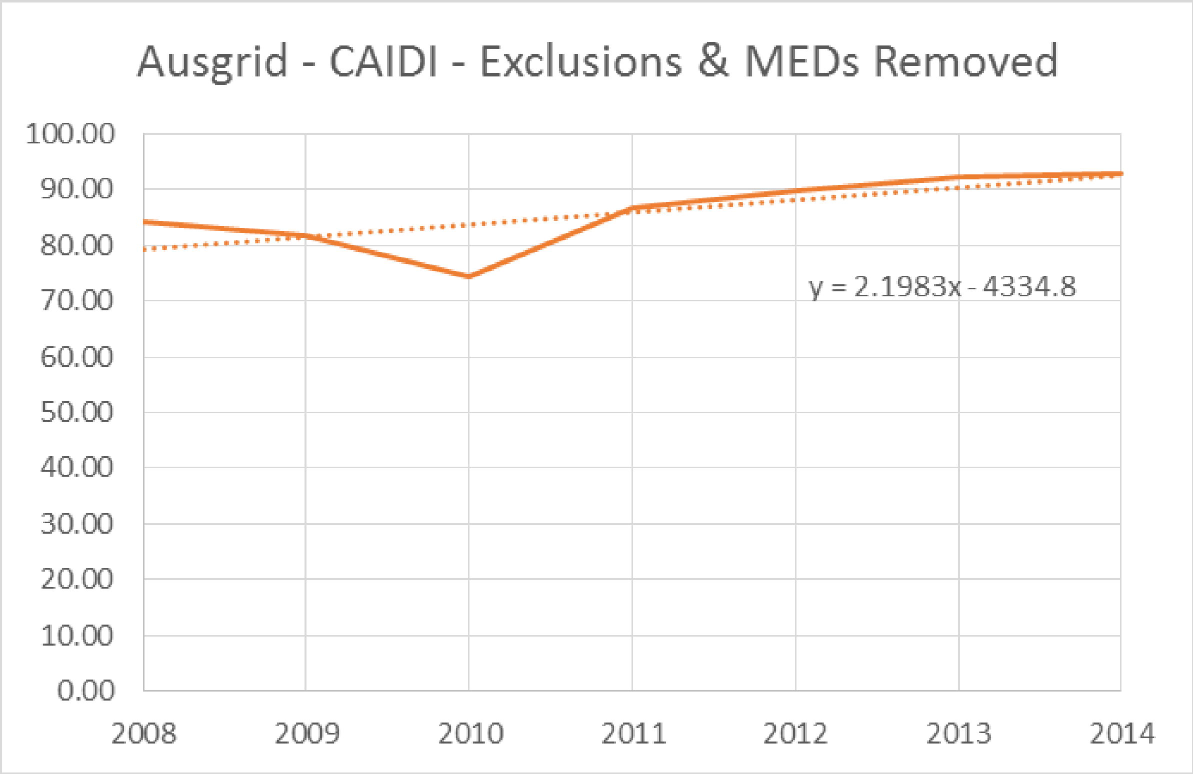
	2008	2009	2010	2011	2012	2013	2014
CAIDI of Network (Exclusions & MEDs Removed)	62.64	60.80	66.58	61.18	54.43	53.77	61.30
Source	2006-13 EB RIN	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN



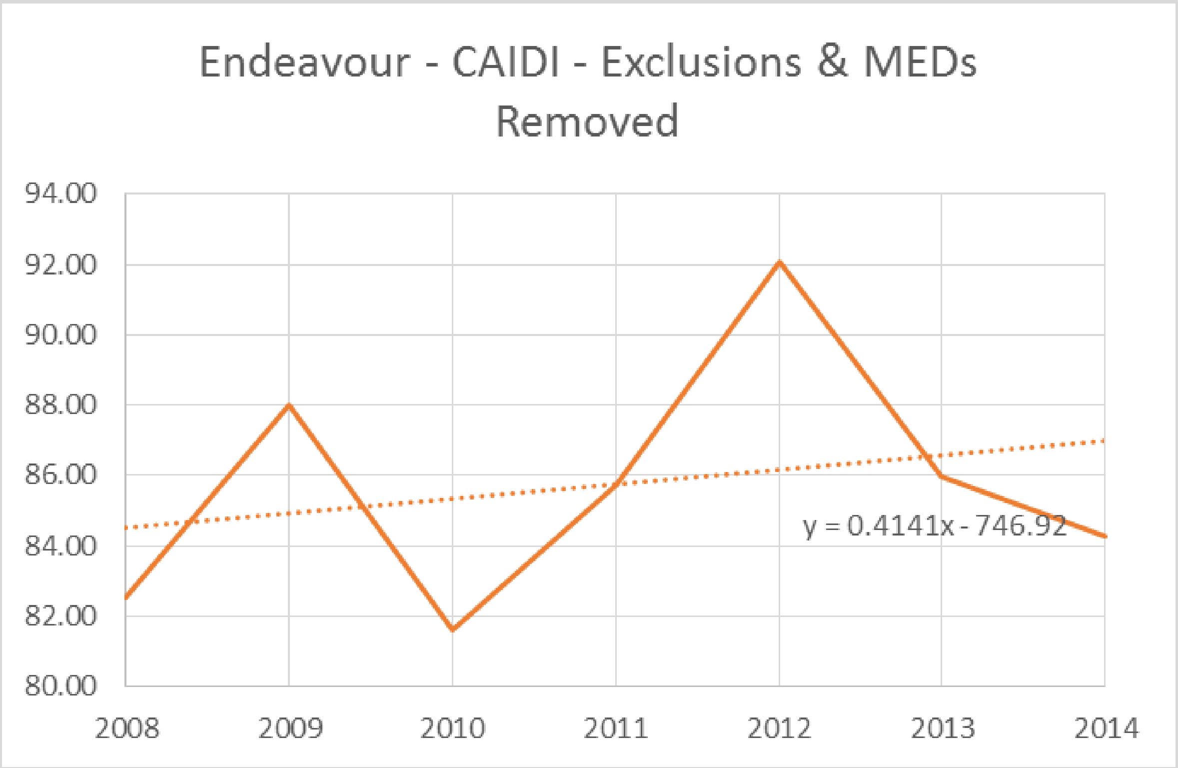
	2008	2009	2010	2011	2012	2013	2014
CAIDI of Network (Exclusions & MEDs Removed)	79.37	93.98	84.87	92.59	94.35	96.88	103.84
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2013 Annual RIN	2014 Annual RIN



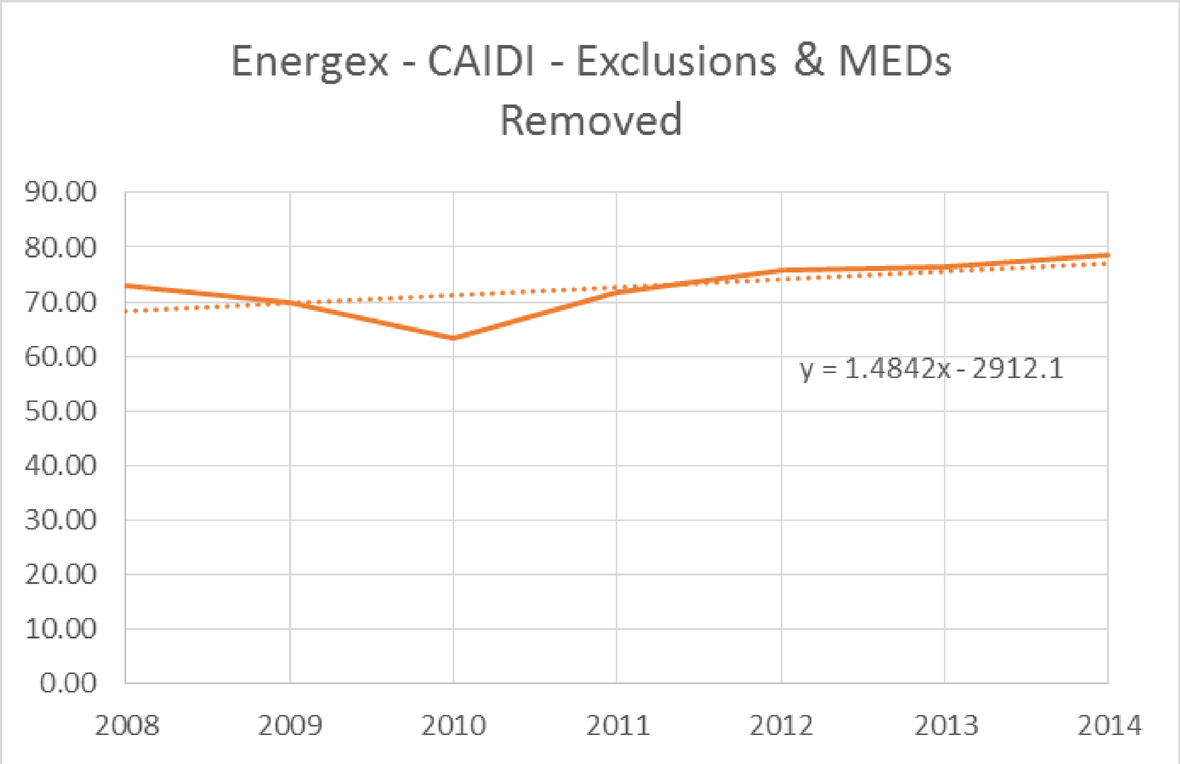
	2008	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	45.71	53.89	45.72	58.41	52.65	48.91	54.71
Source	BM RIN 2006-13	Reset RIN 2016-20	Reset RIN 2016-20	Reset RIN 2016-20	Reset RIN 2016-20	Reset RIN 2016-20	Annual RIN 2013-14



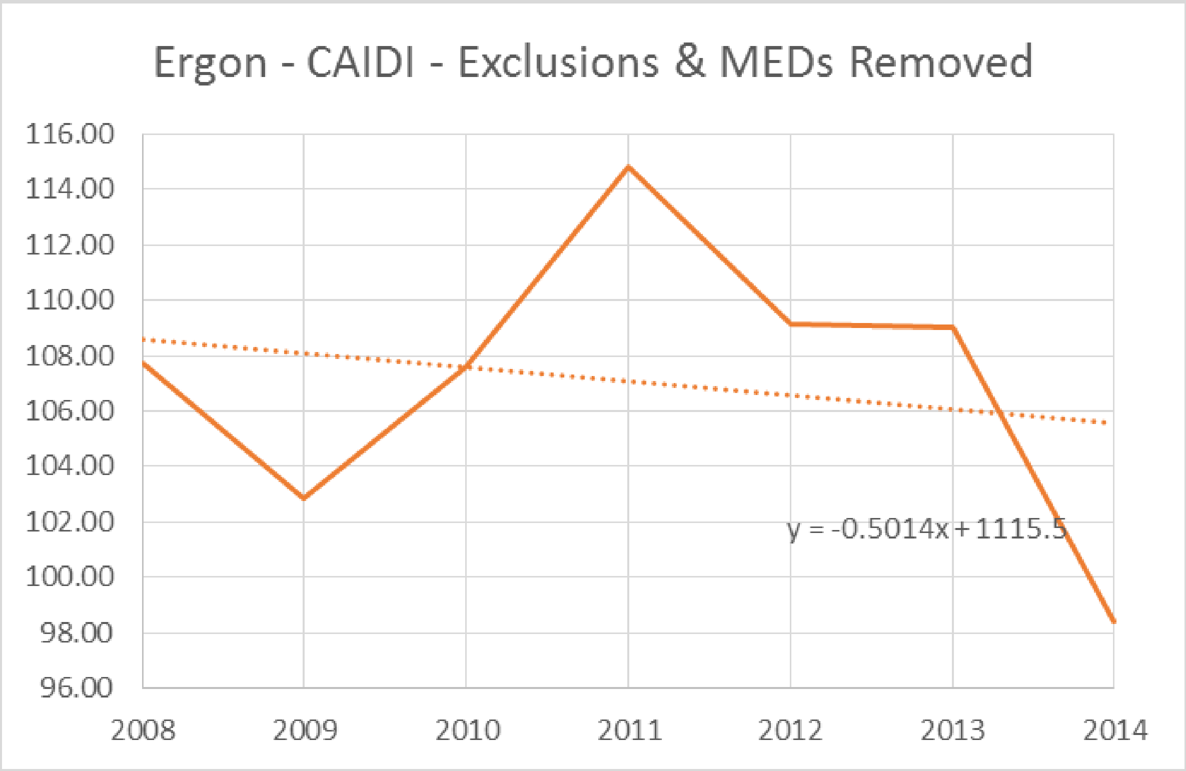
	2008	2009	2010	2011	2012	2013	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	84.30	81.86	74.47	86.56	89.76	92.31	92.75
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2013-14 EB RIN



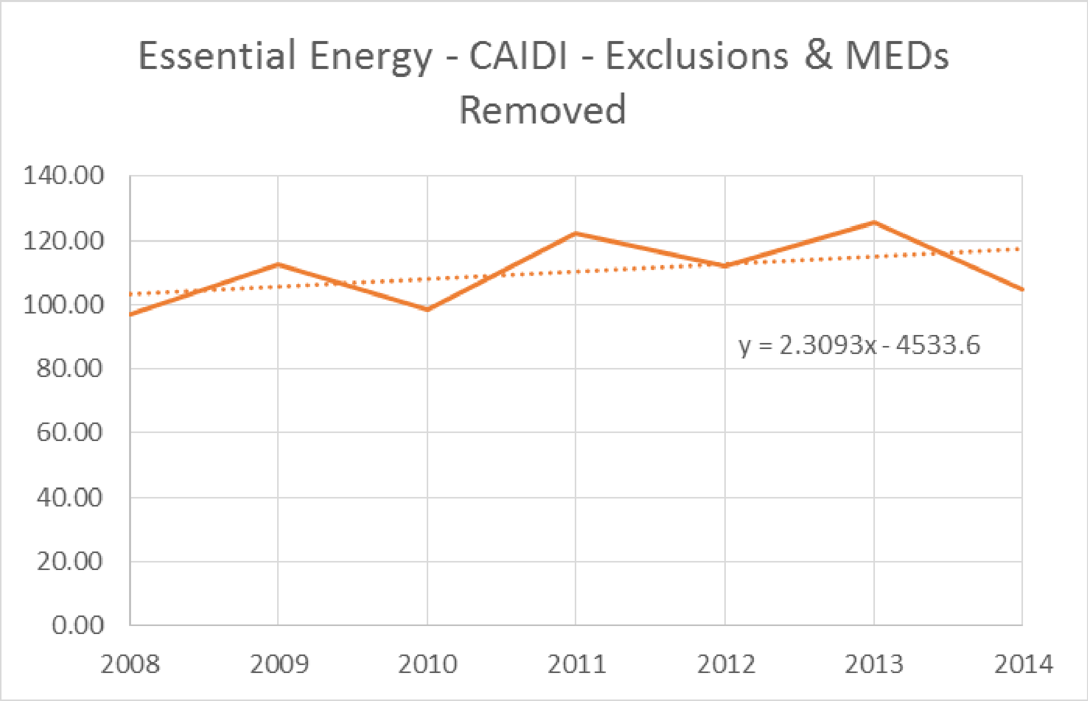
	2008	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	82.55	88.03	81.59	85.71	92.09	85.97	84.29
Source	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2014 Annual RIN



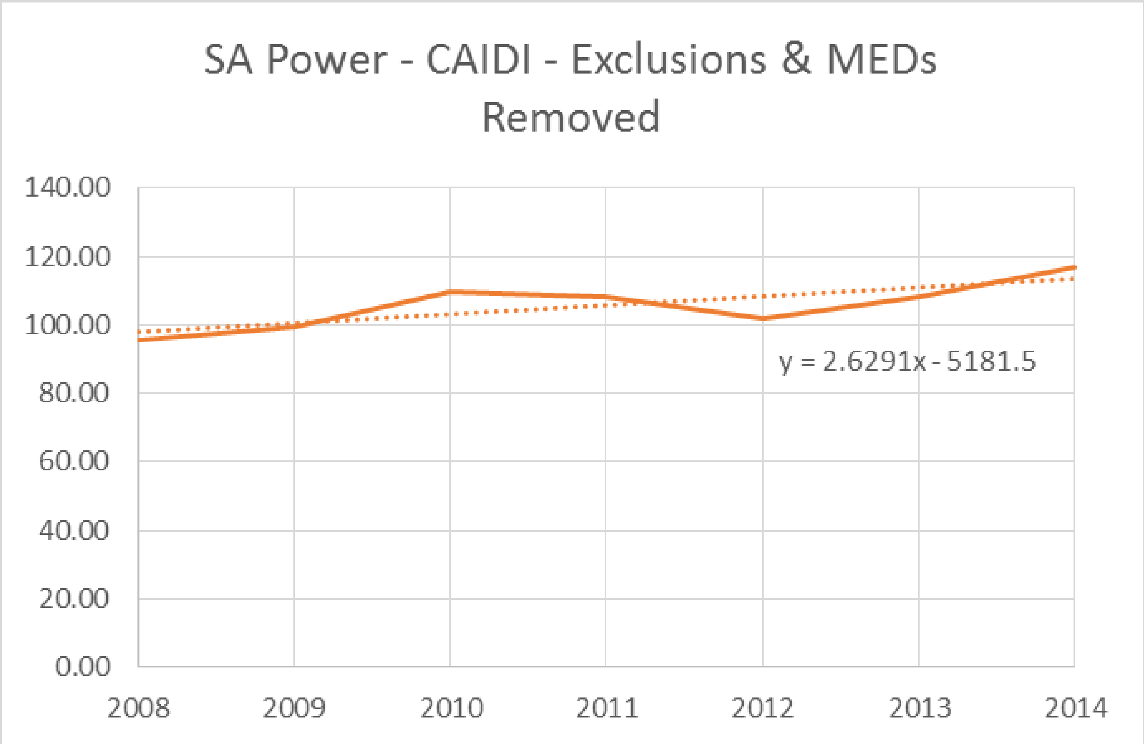
	2008	2009	2010	2011	2012	2012-3	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	72.90	69.99	63.41	71.60	75.72	76.30	78.44
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2012-13 Annual RIN	2013-14 Annual RIN



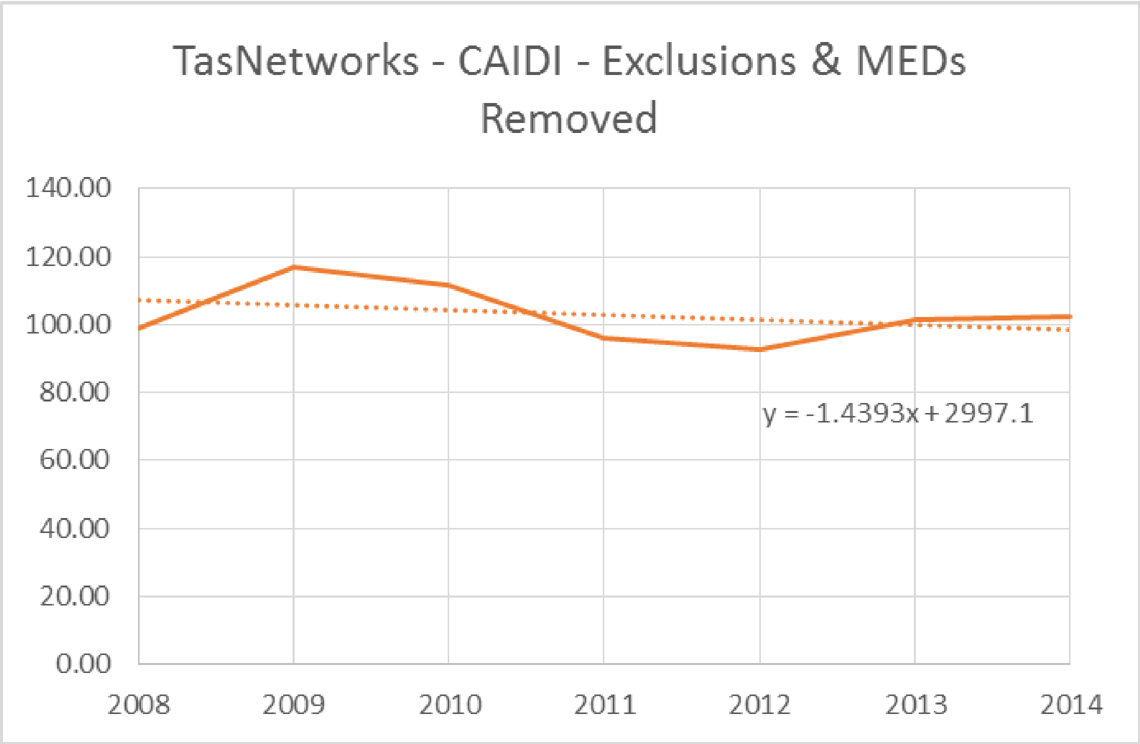
	2008	2009	2010	2011	2012	2012-3	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	107.75	102.85	107.62	114.79	109.15	109.05	98.43
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2012-13 Annual RIN	2013-14 Annual RIN



	2008	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	96.85	112.51	98.45	122.13	111.98	125.88	104.98
Source	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2013-14 Annual RIN



	2008	2009	2009-10	2010-11	2011-12	2012-13	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	95.79	99.27	109.53	108.34	101.79	108.15	116.98
Source	2006-13 EB RIN	2006-13 EB RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN	2016-20 Reset RIN



	2008	2009	2010	2011	2012	2012-13	2013-14
CAIDI of Network (Exclusions & MEDs Removed)	98.87	116.86	111.41	95.86	92.49	101.16	102.21
Source	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2006-13 EB RIN	2012-13 Annual RIN	2013-14 Annual RIN

Appendix D – Metering

D.1 Meter Volumes

As shown in the tables below, we have analysed our meter purchase requirements by estimating the following volumes:

- New connections;
- AMI meter exchanges;
- Faults;
- Returned meter volumes, as a result of abolishments;
- Net meter requirements, being new connections + meter exchanges + faults – returned meter volumes;
- Meter purchase requirements; and
- Current and estimated stock.

Table D-1: New connection volume forecasts

	2016	2017	2018	2019	2020
Single phase single element	7,367	6,753	-	-	-
Single phase single element with contactor	71	65	-	-	-
Single phase two element with contactor	240	220	-	-	-
Three phase direct connected meter	2,088	1,914	-	-	-
Three phase direct connected meter with contactor	70	64	-	-	-
Three phase Current transformer connected meter	164	151	-	-	-
Total	**10,000**	**9,167**	**-**	**-**	**-**

Table D-2: AMI meter exchange volume forecasts

	2016	2017	2018	2019	2020
Single phase single element	1,976	674	-	-	-
Single phase single element with contactor	221	76	-	-	-
Single phase two element with contactor	396	135	-	-	-
Three phase direct connected meter	1,533	523	-	-	-
Three phase direct connected meter with contactor	176	60	-	-	-
Three phase Current transformer connected meter	98	33	-	-	-
Total	**4,400**	**1,500**	-	-	-

New AMI Meters will be installed to replace non-AMI meters in the following circumstances:

- At time of an Additions & Alteration. This may be in the situation where a meter exchange would not normally be required. Approximately half of Additions & Alteration appointments do not require a meter exchange;
- Non AMI Meter Family Failure; and
- On customer request.

Table D-3: Faults volume forecasts

	2016	2017	2018	2019	2020
Single phase single element	1,196	1,244	1,294	1,345	1,399
Single phase single element with contactor	29	30	31	32	33
Single phase two element with contactor	126	131	136	142	148
Three phase direct connected meter	196	204	212	221	229
Three phase direct connected meter with contactor	5	5	6	6	6
Three phase Current transformer connected meter	53	56	59	62	65
Total	**1,605**	**1,670**	**1,738**	**1,808**	**1,880**

Table D-4: Forecast returned meter volumes due to metering contestability and abolishment

	2016	2017	2018	2019	2020
Single phase single element	2,456	2,703	5,438	5,438	5,438
Single phase single element with contactor	64	71	142	142	142
Single phase two element with contactor	283	312	627	627	627
Three phase direct connected meter	660	727	1,461	1,461	1,461
Three phase direct connected meter with contactor	12	13	26	26	26
Three phase Current transformer connected meter	25	28	56	56	56
Total	**3,500**	**3,854**	**7,750**	**7,750**	**7,750**

Table D-5: Forecast net meter volume requirements

Table D-5 is the sum of the volume requirements for new connections, meter exchanges and faults, less the estimated volume of meters returned to stock due to meter abolishment.

	2016	2017	2018	2019	2020
Single phase single element	9,197	6,214	-1,410	-4,093	-4,040
Single phase single element with contactor	289	106	-41	-110	-109
Single phase two element with contactor	620	203	-176	-486	-480

	2016	2017	2018	2019	2020
Three phase direct connected meter	3,597	1,980	-515	-1,241	-1,232
Three phase direct connected meter with contactor	245	117	-8	-21	-20
Three phase Current transformer connected meter	306	215	31	6	9
Total	**14,253**	**8,835**	**-2,119**	**-5,945**	**-5,872**

Table D-6: Stock Status without new orders

	2016	2017	2018	2019	2020
Single phase single element	10,163	3,949	5,359	9,452	13,492
Single phase single element with contactor	2,106	2,000	2,041	2,151	2,260
Single phase two element with contactor	3,508	3,305	3,481	3,967	4,447
Three phase direct connected meter	1,472	-508	7	1,248	2,480
Three phase direct connected meter with contactor	1,401	1,284	1,292	1,313	1,333
Three phase Current transformer connected meter	119	-97	-128	-134	-143
Total	18,768	9,933	12,052	17,997	23,869

Table D-7: Forecast meter purchase volumes

	2016	2017	2018	2019	2020	TOTAL
Single phase single element	-	-	-	-	-	-
Single phase single element with contactor	-	-	-	-	-	-
Single phase two element with contactor	-	-	-	-	-	-
Three phase direct connected meter	1,800	-	-	-	-	1,800
Three phase direct connected meter with contactor	-	-	-	-	-	-
Three phase Current transformer connected meter	200	-	-	-	-	200
Total	**2,000**	**-**	**-**	**-**	**-**	**2,000**

Table D-8: Forecast closing meter stock volumes, given proposed meter purchases

	2016	2017	2018	2019	2020
Single phase single element	10,163	3,949	5,359	9,452	13,492
Single phase single element with contactor	2,106	2,000	2,041	2,151	2,260
Single phase two element with contactor	3,508	3,305	3,481	3,967	4,447

	2016	2017	2018	2019	2020
Three phase direct connected meter	3,272	1,292	1,807	3,048	4,280
Three phase direct connected meter with contactor	1,401	1,284	1,292	1,313	1,333
Three phase Current transformer connected meter	319	104	73	67	58
Total	**20,768**	**11,933**	**14,052**	**19,997**	**25,869**

Table D-9: Forecast expenditure for meter purchases ($, Real 2015)

	Unit Rate	2016	2017	2018	2019	2020	Total
Single phase single element		-	-	-	-	-	-
Single phase single element with contactor		-	-	-	-	-	-
Single phase two element with contactor		-	-	-	-	-	-
Three phase direct connected meter	396	713,055	-	-	-	-	713,055
Three phase direct connected meter with contactor		-	-	-	-	-	-
Three phase Current transformer connected meter	481	96,105	-	-	-	-	96,105
Total		**809,160**	-	-	-	-	**809,160**

D.2 Metering IT ACS/SCS Cos Allocation

Summary

The allocation of AMI IT Cost Recovery Order in Council (CROIC) operating costs to the metering Alternative Control Service (ACS) has been completed. The result of this allocation is that approximately 21% of IT CROIC operating costs are now allocated to support metering functions.

Table 1 below details how each component of IT operating costs has been allocated to the metering ACS. The following assumptions have been made for this allocation.

- Dedicated metering applications are allocated to metering ACS. For example: UIQ, IEE/MTS, MVRS and MV90;
- Infrastructure applications such as WebMethods and B2B are allocated to the metering ACS based on estimate of usage; and
- Where an application is used for both UE and MG the allocation is based on the UE share of this allocation.

It is expected that approximate annual metering ACS IT operating costs would be approximately $3 million based on 2014 calendar year costs.

Allocation by IT cost component

The table below describes how each component of IT operating costs has been allocated to the metering ACS.

Table D-10: Allocation of IT operating costs to Metering ACS

Description	Metering ACS Allocation of CROIC IT	Notes
Internal Resources & Misc.	15%	Based on approximate time staff spends on metering related activities.
Consulting	15%	Consulting used to complement internal resources.
Service Management	15%	Based on approximate time staff spends on metering related activities.
Application Management • Applications support services • Applications software maintenance	28% • 19% • 42%	Primary application support for metering system (UIQ) provided by business based support team therefore that support provided by IT is only 2% of CROIC application support costs. Metering applications are approximately 42% of all CROIC software maintenance costs. (Includes UIQ, MVRS, IEE/MTS, 20% of WebMethods, and an allocation of database support charges.)
Infrastructure Management • Data Centre • Hardware & Software Maintenance • Infrastructure Support Service	22%	UIQ represents approximately 6% of the CROIC IT infrastructure WebMethods uses approximately 20% of the CROIC IT infrastructure and approximately 20% of this is allocated to metering. I.e. 4% IEE/MTS uses approximately 12% of CROIC IT Infrastructure. Total of the IT infrastructure allocated to metering is 22%.
Total	**21%**	**Based on the weighted average across all areas of IT the allocation of CROIC IT operating costs to the metering ACS is 21%.**

Appendix E – ICT Capex - Summary of PoC Initiatives and Justification

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
Consumer Data Access Reference Project Justification – PJ15	The Metering Data Provision Procedures (MDPP) apply when we respond to requests from retailer customers or their agents under NER 7.7(a)(7). Under the new Rules we are required to comply with the new MDPP from 1 March 2016 for requests from retail customers and their agents. This obligation applies to all metered customers regardless of meter type and customer size. To comply with the rule change, we need to: • Enable requests for data to be raised by a customer or the customer's authorised representative[93]; • Ensure that for each request there is sufficient information to verify the customer at the premise, verify the customer's relationship with the authorised representative and meet any applicable privacy legislation requirements, including obtaining customers consent for disclosure of confidential information[94];	This project requires changes to the following systems and business processes: • Our external website – providing authentication of customers and representatives and facility to request data; • Our connection point and meter data management systems to verify customers and extract meter data; • Our contact centre business processes and scripts; • Development of data extract processes to generate the required file formats; and • Implementation of request tracking and data recording and management. Cost estimates are based on modification of existing systems and improved manual processes.	This project supports compliance with the AEMO MDPP rule changes arising from the Power of Choice reform that "Enables consumers to make better and informed choices about energy products and services by making it easier for consumers to get access to their electricity consumption information". The project aligns to the capex objective of complying with applicable regulatory obligations.	Refer document reference PJ15 for full details. **Efficient Cost:** In determining the proposed solution we considered the cost of a largely manual solution (using its contact centre to capture requests and initiate processes to produce the required output for customer consumption) and compared this with a self-service solution utilising existing processes used for meeting the Victorian AMI Tariffs Order. The proposed solution, supporting a combination of self service and optional manual requests was determined to be the most cost-effective required to meet the objectives. **Cost of a Prudent Operator:** As a prudent operator we balance the forecast cost of a basic manual solution to meet the NER objectives against that of a fully automated self-service solution designed specifically to meet the new requirements. The proposed solution, provides the most cost effective solution, utilises existing capability and enhancements to existing systems and processes. **Demand and Cost inputs:** Based on current customer requests and given the Power Of Choice reforms, an increasing awareness and interest in consumption data, we estimated that the volume of requests will increase. Cost estimates are based on extending the existing automation for high volume transactions and improved manual processing for lower volume transactions.

[93] NER 7.7 (a) (7)

[94] NER 7.7 (a1)

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
	• Respond to the customer within a certain period of receiving the request[95]; • Provide data formats consistent with the new MDPP[96]; • Provide a customer guide to assist retail customers to understand and interpret detailed interval data formats[97]; and • Implement data management and reporting activities to enable reporting against the obligations.			
Customer Switching Reference Project Justification – PJ16	Improve the efficiency of customer switching through improved automation of the switching process enabling customers to transfer retailers on estimated readings as prescribed in the AEMC Final Report published on 10 April 2014. The Final Report includes requirements to: • Improve automation of consumer transfer process enabling consumers to switch retailers more efficiently; • Allow transfers on estimates for manually read meters; • Address process and data quality issues (create standard address	This project requires changes to the following systems and business processes: • Modify our connection point management, billing and market systems to improve automation of consumer transfer process enabling consumers to switch retailers more efficiently. • Cost estimates are based on modification of existing systems.	This project is required to comply with proposed changes to the NER and National Energy Retail Rules as outlined in the AEMC Final Report on Electricity customer switching published 10 April 2014.	Refer document reference PJ16 for full details **Efficient Cost:** A number of our business processes are impacted by the planned changes to the NER including our systems that support billing, connection point management and market interactions. Due to the number of transactions and volumes of data involved it is not feasible to implement these changes without system changes. **Cost of a Prudent Operator:** As a prudent operator we are preparing for the introduction of improved customer switching arrangements as required by the AEMC Final Report. **Demand and Cost inputs:** Costs are based on a process-by-process review, identification of systems impacted and experience delivering comparable projects.

[95] AEMO, Meter Data Provision Procedures, 1 September 2015, clause 2.1 (c) to (g)

[96] AEMO, Meter Data Provision Procedures, 1 September 2015, clause 4.2,4.3 and 4.4

[97] AEMO, Meter Data Provision Procedures, 1 September 2015, clause 4.5 (d) (e) – (e)

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
	format and cleanse NMI standing data); • Have the LNSP become the master for address data – new market transactions are required; • Improve rejections processes; and • Undertake reporting, including of transfer performance statistics.			
Demand Response Mechanism Reference Project Justification – PJ18	Demand response mechanism – option for demand side resources to participate in the wholesale electricity market. This provides capabilities for demand side mechanisms to be established so that large consumers can sell demand into the NEM through an aggregator to facilitate efficient Demand Side Participation (DSP) as outlined in the COAG Energy Council rule change request of 25 March 2015 and in the AEMC consultation paper of 5 November 2015.	This project requires changes to our systems and business processes including: • Establishing the Demand Response Aggregator (DRA) within our customer systems and associate customers with their DRA. • Updating our business to business gateway to receive notifications from DRA to ensure network operations are aware of changes to network load.	This project is required to comply with proposed changes to NER for the implementation of the demand response mechanism. The project supports our obligations to meet and manage demand on our network by ensuring that we are informed of DRA activities on our network.	**Efficient Cost:** Given that DRAs will be operating to the AEMO Spot Market Operations Timetable we propose that automatic messaging will be required to ensure we are keep informed of changes to network load. Estimates are based on extending our existing messaging infrastructure to support the new function at an incremental cost only. **Cost of a Prudent Operator:** As a prudent operator, we are preparing for deployment of demand management by DRAs for UE's large customers. **Demand and Cost inputs:** It is expected that the DRAs will target less than 1% of our customers. Software and hardware estimates are based on commensurately low transaction rates. Although transaction rates are low, the real-time nature of transactions will require a degree of automation.
Metering Competition Reference Project Justification – PJ19	This establishes a competitive market for the supply, installation and operation of advanced metering with communications capability. The AEMC final rule of 26 November 2015 provides for the following:	Introduction of the Metering Coordinator role, the minimum meter specification and the shared market protocol has significant impacts on many of our business processes and systems.	The project is required to comply with the changes to the NER for the introduction of Metering Competition published on 26 November 2015. The project maintains reliability of supply by including support for	**Efficient Cost:** Changes are required to many of the processes implemented in our existing business systems. Due to the number of transactions and volumes of meter data involved it is not feasible to implement many of these processes without system changes. It has been

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
	• Changes to the overall responsibility for metering services under the NER to promote competition in the provision of metering and related services; • A Metering Coordinator to take on roles additional to those currently performed by the Responsible Person so that the security of, and access to, advanced meters and the services they provide are appropriately managed; • The minimum services that a new or replacement meter installed at a small customer's premises must be capable of providing; • The circumstances in which small customers may opt out of having a new meter installed at their premises; • The entitlement of parties to access energy data and metering data to reflect the changes to roles and responsibilities of parties providing metering services; • LNSPs to use network devices installed at customers' premises that assist them to monitor and operate their networks. Permits retailer to arrange for a Metering Coordinator to remotely disconnect or reconnect a small customer's premises in specified circumstances;	The rule changes impact the end to end management of meters, meter data, service orders, billing and market interaction. Requirements include: • Establishing the metering coordinator role; • Providing support for meter and participant churn and associated market transactions; • Enabling and managing receipt of metering data and meter and data stream configuration from third parties for all meter types; • Establishing communications infrastructure and systems to enable open access to metering data and functions and the adoption of the Shared Market Protocol. This includes capabilities to access other metering coordinators' systems and provide access to our deemed metering coordinator's system; • Establishing capability for real time metering transactions; and • Providing support for metering to the national minimum standard. This project includes market testing of system changes with AEMO and existing and new market participants. The project will be implemented over 2016 and 2017.	management of network devices to monitor network performance and the management of interactions with competitive metering providers.	determined that these capabilities can be most efficiently delivered by modifying existing systems. **Cost of a Prudent Operator:** As a prudent operator we are preparing for the introduction of meter competition on the 1 December 2017 as prescribed in the NER. **Demand and Cost inputs**: From 1 December 2017 all new and replacement metering will be provided by contestable metering providers. Transaction volumes are based on expected numbers of new customers and rate of replacement of existing metering. Costs are based on a process by process review, identification of systems impacted and experience delivering comparable projects.

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
	• Changes to the model terms and conditions of standard retail contracts to reflect the changes to the roles and responsibilities of parties providing metering services. • Changes to aspects of the governance arrangements for B2B procedures, including: – Expanding the membership of the IEC; – Expanding and updating the content requirements for B2B procedures to provide for new B2B communications that support services enabled by advanced meters; – Creating a new accredited party role for parties wishing to use the B2B e-hub; – Updating the cost recovery mechanism for the new B2B arrangements.			
Multiple Trading Relationships	On 19 November 2015, the AEMC released its Draft Determination on the Multiple Trading Relationships rule. The rule was intended to enable any arrangement whereby a customer engages with more than one retailer at a premise. This could include having different retailers for different parts of the premises or different appliances. In the Draft Determination the AEMC decided not to make a draft rule as the rule change request is not in the long term interests of consumers for the reasons set out in its Draft Determination. On this basis we consider that the Rule will not proceed and a new rule change request might be submitted once more detailed work has progressed. We have therefore not included costs for this Rule in our RRP.			
Network Pricing Reference Project Justification – PJ21	**Distribution network pricing arrangements** This enables DNSPs to set prices that reflect the cost of providing their services	The implementation of cost reflective network pricing requires us to modify our billing and reporting systems. In particular:	The project is required to comply with the NER changes for Distribution Network Pricing Arrangements made on 24 November 2014. This rule requires	**Efficient Cost:** Changes are required to our systems that support billing. Due to the number of transactions and volumes of data involved it is not feasible to implement these billing changes without system

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
	so that consumers can make informed choices on the way they use electricity. As detailed in the AEMC final determination of 27 November 2014, DNSPs must comply with the following new pricing principles: • Each network tariff must be based on the long run marginal cost of providing the service; • The revenue to be recovered from each network tariff must recover the network business' total efficient costs of providing services in a way that minimises distortions to price signals that encourage efficient use of the network by consumers; • Tariffs are to be developed in line with a new consumer impact principle that requires network businesses to consider the impact on consumers of changes in network prices and develop price structures that are able to be understood by consumers; • Network tariffs must comply with any jurisdictional pricing obligations imposed by state or territory governments. But if network businesses need to depart from the above principles to meet jurisdictional pricing obligations, they must do so transparently and only to the minimum extent necessary.	• New cost reflective tariffs have a demand components and require implementation of minimum contract capacities within our billing system; and • New reporting is required to monitor the performance of cost reflective tariffs.	DNSPs to develop and implement cost reflective tariffs.	changes. It has been determined that this capability can be most efficiently delivered by modifying existing systems. **Cost of a Prudent Operator:** As a prudent operator we are preparing for the introduction of cost reflective on the 1 January 2017 as prescribed in the NER. **Demand and Cost inputs:** It is planned that from 1January 2017 new cost reflective tariffs will become operational. Costs are based on a process by process review, identification of systems impacted and experience delivering comparable projects.

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
Demand Management AEMO Reporting Reference Project Justification – PJ25	This involves improving demand side participation information provided to AEMO by registered participants. This provides AEMO information on contracted and price responsive demand side participation programs. This will allow AEMO to produce better load forecasts. In its final determination of 26 March 2015 the AEMC has introduced a new clause 3.7D of the NER, which requires Registered Participants to provide demand side participation information to AEMO in accordance with the demand side participation information guidelines.	This project requires the implementation of systems and processes to manage the end to end deployment of non-network solutions including Demand Response (DR) to meet customer demand. These processes include: • Forecast Available DR Load with Network Model Precision • Monitor Customer Event Participation • Provide information to AEMO to support AEMO forecasting. It is expected that as an increased number of non-Network options for meeting demand are deployed, reporting to AEMO will be supported by the Demand Management IT platform (PJ26).	This project is required to comply with clause 3.7D of the NER.	**Efficient Cost:** As the number of customer engaged in demand management solutions increase that manual solutions will be no longer efficient and an automated solution will be required. **Cost of a Prudent Operator:** As a prudent operator we are preparing for wide deployment of non-network options to meet customer demand for SCS. We have trialled the use of demand management and determined cost effective deployment of non-network options, at scale, will require automation of critical processes including reporting. **Demand and Cost inputs:** We have estimated the proportion of future demand that could potentially be met by non-network options. We consider this to be a realistic forecast. To manage non-network options without automation the forecast operating cost would render non-network options as uneconomic.
Demand Management IT Platform Reference Project Justification – PJ26	This involves reform of the demand management and embedded generation connection incentive scheme. This involves enables the deployment of demand management as a cost effective alternative to traditional network investment. In its Final Determination of 15 August 2015 the AEMC has amended clause 6.6.3 of the NER to establish a demand management incentive scheme to reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers.	This project requires the implementation of systems and processes to manage the end-to-end deployment of non-network solutions including Demand Response (DR) to meet customer demand. These processes includes: • Manage programs and enrol customers; • Track customer enrolment campaign performance; • Manage customer installs and maintenance calls; • Manage DR assets and provisioning of devices;	The Demand Management IT platform provides the capability to deploy non network options to meet the demand for SCS in the most cost effective manner (NER clause 6.6.3). The demand management IT platform will also contribute to maintaining network reliability by providing the capability to manage distributed energy resources that may be deployed as an alternative to load shedding.	**Efficient Cost:** Greater deployment of non-network options requires new systems to manage the end to end demand management process. Without a demand management IT platform it is not cost effective to widely deploy non-network options. We have determined that full manual management of this process is not efficient. The proposed solution (PJ26) automates manually intensive processes associated with deployment of demand management. **Cost of a Prudent Operator:** As a prudent operator we are preparing for widespread deployment of lower cost non-network options to meet customer demand for SCS. We have trialled the use of demand

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
		• Forecast available DR load with network model precision; • Optimize DR dispatch for cost, contract, decay, snap-back; • Create DR events and notify participants; • Manage devices via existing load management systems (including UE and customer owned devices and via multiple channels (DMS/SCADA, AMI network, internet or other); • Integrate of third party aggregators; • Monitor customer event participation; • Create customer baseline calculation and settlement data; • Provide information to AEMO to support its forecasting (refer Rule Change – Improving Demand Side Participation Information provided to AEMO by Registered Participants). (Delivered by separate Demand Management AEMO Reporting Project, NER clause 3.7D) • Interface or integrate with third-party non-network provider platforms We propose to support the above processes with a commercially available, purpose-built demand management IT platform. These platforms are readily available, mature and have been deployed in other countries.		management and determined cost effective deployment of non-network options, at scale, will require automation of critical processes. **Demand and Cost inputs:** We have estimated the proportion of future demand that could potentially be met by non-network options. To manage non-network options without automation the forecast operating cost would render non-network options as uneconomic.

UE Project	POC Rules	Business, System and Cost impacts	Alignment to NER Capital Expenditure Objectives	Alignment to Capital Expenditure Criteria
Embedded Networks Reference Project Justification – PJ27	In its Final Determination of 17 December 2015 the AEMC amended the NER to require LNSPs to: • Record and maintain the list and details of accredited and registered Embedded Network Managers (ENMs) (amendment clause 7.16.5) • Record and maintain the ENM assigned for an embedded network (amendment clause 7.3.1.fa) • Receive, validate, and responds to transactions from ENMs as per the B2B Procedures (amendment clause 7.2A.4) • Receive, validate, and respond to an ENM applying for a NMI for each metering installation within the embedded network (amendment clause 7.3.1e); and • Publish meter data to ENM (amended clause 7.7.4a).	This project requires the following changes to our connection point management and market systems: • Apply transaction and business acceptance/rejection logic for each B2B or CR message received from an ENM. Ensure that our systems appropriately handle child NMI's with a UE NMI range and with a new NMI range where AEMO has provided a non UE NMI to the ENM to use on second tier children; • Record in the Embedded Network Parent NMI the Exempt Embedded Network Service Provider (EENSP) and if nominated the ENM and the Role ID of the ENM. This can change over time and historical information needs to be maintained; • As the role is contestable, we will have to support EN manager churn; and • Capture life support information at the Parent NMI level when a child NMI (on or off-Market) has life support needs. This information is expected to come from the parent FRMP as per the current standard industry process. Update internal life support procedures.	The project is required to comply with the changes to the NER for the introduction of Metering Competition published on 17 December 2015. The project contributes to the safety of customers through improved processes for the management of life support customers on embedded networks.	**Efficient cost of achieving objectives:** Changes to our systems are required to support connection point management and market interaction. Due to the number of transactions and volumes of data involved it is not feasible to implement these billing changes without system changes. **Prudent cost:** As a prudent operator we are preparing for the introduction of the changes to the NER to support Embedded Networks by 1 December 2017. **Realistic expectation of Demand and cost inputs:** It has been assumed that from 1 December 2017 new rules for management of Embedded Network will become effective. Costs are based on a process by process review, identification of systems impacted and experience delivering comparable projects.

Appendix F – Opex step changes

This appendix justifies the Opex step changes that are detailed in section 6.6, which are re-presented below.

New regulatory obligations – annual			Regulatory Proposal	AER Preliminary Decision	Revised Proposal
1.	a.	Power of Choice – Metering Competition	3.5	-	4.9
	b.	Power of Choice – Customer Access to Data	1.7	-	1.8
	c.	Power of Choice – Embedded Network	0.7	-	Withdrawn
	d.	Power of Choice – Demand Management IT Platform	1.6	-	1.6
	e.	Power of Choice – Network (Chapter 5 and Chapter 5A – Embedded Generation Connection, including Solar)	3.5	-	Withdrawn
2.		Regulatory Information Notice reporting	1.6	-	4.6
3.	a.	Energy Safe Victoria safety obligations	1.0	-	Withdrawn
	b.	2015 Electricity Line Clearance Regulations (previously named Energy Safe Victoria rule changes)	8.7	-	11.7
4.	a.	Effortless Customer Experience Program	6.0	-	Withdrawn
	b.	Stakeholder engagement	1.3	-	1.3
	c.	Council trees	3.0	-	Merged with 3b
5.		Customer charter	0.7	-	Withdrawn
6.		Regulatory submission cost	2.3	-	Withdrawn
7.	a.	Neutral Testing	0.4	-	2.3
	b.	Network Planning and Analytics - IT Capital Program	4.1	-	4.1
8.		Guideline 11 EWOV Direction	4.5	-	Withdrawn
9.		IT security costs	4.0	-	3.9
10.		Insurance premiums	2.3	-	Withdrawn
11.		Pole top inspection	2.4	2.4	2.4
12.	New	New pricing obligations		n.a.	2.5
13	New	NECF		n.a.	0.7
		Real price escalations	0.5		-
		Total	**53.8**	**2.4**	**41.6**

Name	1a. Power Of Choice Metering Competition					
Amount ($M, Real 2015)	2016	2017	2018	2019	2020	Total
– Regulatory Proposal	1.2	0.5	0.6	0.6	0.6	3.5
– AER Preliminary Decision	-	-	-	-	-	-
– RRP	-	0.2	1.5	1.6	1.6	4.9
Legislative / regulatory requirement	On 26 November 2015, the AEMC released the Final Determination on the National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No 12 and the National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015 No 1. The final rules amend the NER and the National Energy Retail Rules (NERR). Whilst the NERR do not currently apply there is an expectation that Victoria may amend its instruments over the coming months to follow the national approach. The new rules state that Type 7 metering is exclusively provided by the LNSP and all other meter types are open to competition. The retailer, who is the Financially Responsible Market Participant (FRMP), appoints the Metering Coordinator (MC). The new MC appoints the Metering Provider (MP) and the Metering Data Provider (MDP). This new rule places an end date, 1 December 2017, on the current exclusivity derogation which the Victorian DNSPs have for 160MWhpa and below customers. The final rule therefore changes overall responsibility for metering services under the NER to promote competition in the provision of metering and related services by: • Providing for the role and responsibilities of the existing Responsible Person (RP) to be provided by a new type of Registered Participant – the MC; • Allowing any person to become a MC, subject to meeting the registration requirements, other than at transmission connection points and in relation to type 7 metering installations; • Permitting large customers and non-market and exempt generators to appoint their own MC at distribution connection points; and • Requiring a retailer to appoint the MC, except where another retailer has appointed its own MC. The amendments to the NER comprise five schedules. Schedules 1 and 5 commenced on 26 November 2015 and form part of the current rules to facilitate the move to metering competition, which: • Enables a new category of market participant – the MC; • Requires the AER to develop and publish a national ring fencing guideline; • Amends the Victorian derogation so that it expires on 1 December 2017, rather than the earlier of 31 December 2016 or on the national rules for metering competition and an orderly transition for Victoria; • Defines a large customer in accordance with the NECF, or, in the case of Victoria, in accordance with the jurisdictional legislation (business customer above 40MWhpa); • Establishes obligations on parties to amend and publish revised procedures or create new procedures; and • Provides a framework for the LNSP providing type 5 and 6 metering services to be deemed appointed or appointed by the FRMP in the MC role on agreed terms and conditions. Schedules 2, 3 and 4 provide more detailed rules, which commence on 1 December 2017 and facilitate the change in the existing rules – particularly regarding changes in the roles and responsibilities for metering services, as well as competitive metering arrangements and services provision: • Chapter 5 on connections is amended to include meter type 4a with type 5 in a number of clauses;						

Name	1a. Power Of Choice Metering Competition
	• Chapter 5A will be introduced in Victoria sometime in 2016 to amend the connection service definition; • Part C of Chapter 8 will extend the confidentiality provisions to include not just registered participants but also MP and MDPs; • Schedule 3 is a complete rewrite of the existing NER chapter 7; and • Schedule 4 updates or introduces new definitions. The rules for metering competition and related services are now final. The rules clearly place a range of obligations on parties to update NEM and B2B procedures to facilitate metering competition and related services. The AEMC's shared market protocol rule will facilitate the additional B2B transactions required for the minimum metering specification. In our roles as LNSP and deemed MC we must be ready to meet the new requirements and facilitate metering competition on our local network.
Services / capability requirements	The new rules and changes to procedures will introduce significant changes to many activities across our business, particularly in the traditional role of LNSP – which involves providing connection, energisation and supply services – including provision of the following services: • Network management: ○ Receive retailer planned interruption notices and provide relevant information to a customer who may have had a supply interruption or no supply, and then refer the customer back to a retailer[98]; ○ Increased levels of communications management as AMI meters are retired and we need to supplement network analytical data[99]; ○ Increased levels of communications management caused by retrospective transfer of responsibilities in systems after field work completed; ○ Increased levels of coordinated planned outage notifications to customers to enable an MC to exchange a meter[100]; and ○ Increased levels of faults handling resulting from storm events where customers' meters are not able to be exchanged and customer supply restored. • Customer management ○ Increased network tariff changes as there is no obligation to provide same meter configuration;[101] ○ Increased levels of claims and complaints caused by network tariff changes and third party meter exchanges and missing churn day data; ○ Increased levels of scheduling activities to coordinate with MC the meter exchange where assisted DNSP planned interruptions, e.g. multi-occupancy or pits;[102] ○ Forward meter enquiries to retailer call centre;[103] ○ Increased level of complexity and coordination for new connections and initial energisation and for supply upgrades;[104] ○ Ongoing management of appointed MC contracts and services, including transition to a competitive meter.[105]

[98] NERR 99A (1) and (3)

[99] Examples are equipment loading analysis, network planning and meet ESC voltage reporting requirements

[100] NERR 91A (d)

[101] NER Schedule 7.5

[102] NERR 91A (d)

[103] NERR 101

[104] NER 5A.A.1, changed connections services

[105] NER 11.86.7

Name	1a. Power Of Choice Metering Competition
	• Data management and Connection activity: ○ Increased data management requirements as increased data versions need to be accommodated from third party MDPs, resulting in increased billing complaints; ○ Increased follow up for missing data for network billing due to lower service data quality;[106] ○ Notify retailer of DNSP de-energisations and re-energisations;[107] ○ Receive notifications of retailer de-energisation and re-energisations and ensure we do not re-energise a retailer initiated de-energised customer;[108] ○ Manage responses to site access, meter location and key access issues;[109] ○ Additional workload to coordinate connections with MCs, MPBs, RECs, including requirements to manage real time re-scheduling as well as dealing with exceptions that Retailers / MCs will make in the market; and ○ New activity to establish and manage appointments where the new MC is required to bring meter installation up to standard when defects exist (a new LNSP obligation). • Meter management ○ Notify retailer of required faults replacements[110]; ○ Notify retailer of non-compliant meters – faulty communications or visual display etc.[111]; ○ Notify retailer of non-compliant meter and provide the family test results[112]; ○ Follow-up retailer where new MC not appointed to transfer responsibilities, follow up to occur at least twice[113]; ○ Compare notified retailer against current retailer to ascertain that there has been no retailer churn and the current retailer is unaware of the need to exchange meter[114]; ○ Undertake audit activity to ensure that work is undertaken safely in our area; and ○ Manage removal of current transformers which are part of the regulated meter service. We recognise that some of the changed services above will be dealt with by automated systems, however there will be exceptions management, and call centre interactions with retailers and customers for many of the service changes listed.
Activities / processes impacted to deliver service	The rules place additional workload on us as we manage the exceptions and additional activities as outlined below: **Network management** • Receive retailer planned interruption notices and provide relevant information to the network control room/service desk and IT systems to enable an appropriate customer response when the customer queries a supply interruption or no supply, refer customer back to retailer; • Manage increased levels of communications management as AMI meters are retired and we need to supplement network analytical data with the use of network devices; • A number of meter exchanges will occur in the field and then later be updated into systems. This will create missing metering data and network data and will need to be investigated;

[106] Schedule 7.5

[107] NERR 104 (1) and 106A (5)

[108] NERR 104 (2) and 106A (2) and (6)

[109] MP SLP

[110] NER 7.10.1(10), 11.86.7(d)(4), 11.86.7(g)(3) MC management of metering installation in line with Chapter 7 obligations, as current deemed or appointed regulated MC we will be unable to bring the metering installation into a compliant state

[111] NER 7.10.1(10), 11.86.7(d)(4), 11.86.7(g)(3)

[112] NER 7.9.1(h), 7.9.1(i)(2) maintenance replacement

[113] NER 7.10.1(10), 11.86.7(d)(4), 11.86.7(g)(3), 11.86.7(h)

[114] NER 7.10.1(10), 11.86.7(d)(4), 11.86.7(g)(3), 11.86.7(h)

Name	1a. Power Of Choice Metering Competition
	• Whilst back office resources will arrange appointments, field crews will need to meet appointment timeframes to ensure that connections are de-energised and then re-energised to allow the MCs appointed MPs to undertake the meter exchange. This is likely result in field crews being asked to stay at site or to come back at certain times and will result in less efficient use of resources; and • Increased levels of faults handling resulting from storm events where field crews need to identify the retailer and notify the need for a new meter. **Customer management** • Increased exception management activities in the Service Desk to manage exceptions including changing network tariffs where meter details are not established in MSATs, MPBs not completing meter changes in MSATs (as occurs now in the type 1-4 customer segment) and where we receive meter data, resulting in an exception; • Additional activities required to validate work prior to initiating Service Orders to perform UE's role as either LNSP or default MC; • Increased activities associated with dealing with customer complaints, and managing customers' expectations associated with delays / missed appointments that are likely to result from the coordination of an increased number of providers required to close out issues on customers' sites; • Increased market communications (Service Orders) including email and telephone communications with MCs, their MPBs and RECs and customers to resolve errors and coordinate activities across a number of service providers; • Increased complexity in processes with retailers organising connections and additions/alterations including increased customer interactions and complaints due to uncertainty of the role of the retailer/MC/MPB and the DB. There is already a level of non B2B communication between Retailers and Network (including our third party service providers) in an environment where the B2B arrangements for connections and ads/alts are relatively straight forward and unilateral; • Increased complexity of communication as a result of increased market stakeholders, including an increased level of complexity from network field resources as they will be required to meet appointments with multiple MPBs for supply connection and reconnection activities. At present the metering & supply connection or the reconnection process involves a minimum of appointment setting requirements. The increase in appointment setting activity will result in re-appointments with multiple parties as a result of travel delays, connection points taking longer than planned / allowed, and the normal inability of key participants to attend set appointments. The level of coordination or resetting appointments will be considerable. **Data management** • Manage increased complexity in relation to connection, metering and energisation tasks, to ensure that new connections are appropriately established in our systems (most Connections are issued directly to the field and do not require appointment setting): • Establish new data-streams and to assist with the network tariff components; • Follow up with 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; • Additional effort and complexity in following up meter data exceptions from MC's MDPs. • Increased activities in network billing associated with obtaining meter data from multiple data providers, • Increased number of retailer disputes, resulting in higher number of cancel and rebilling of network invoices. • Increased exceptions that will result from communicating and actioning missing or incorrect metering data from MC's MDPs to ensure that accurate network invoices are issued in a timely manner. Under the current regulatory environment the involvement with external MDPs is limited to T1-4 (Large Market customers).

Name	1a. Power Of Choice Metering Competition
	• Increased activity associated with obtaining missing or incorrect meter data from multiple MC's MDPs. For small customer's meters this is a new function and our experience with large customers is significant exception management / effort occurs. This has a flow on impact on Network Billing in that exception in Meter data received will increase the number of cancellation and re-billing of Network invoices; and • Manage 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), which is estimated to impact 2,000 meter transfers per month **Meter management** • Additional activity associated with auditing to ensure that third party meter providers are installing meters safely in the network and not causing any network related issues as a result of the meter installation by third parties. This has to be sufficient to complete audit, either sample or inspection of each site and includes all Connections, Additions/Alts associated with meter change, retailer initiated change of meter, fault replacement, and replacement based on family groups.
Cost build-up	The calculation of our forecast costs is described as follows: **Network Management** • One Full Time Equivalent (FTE) internal employee in the Network Operations Centre to manage the increased communications management activities including managing network devices at $100k per annum, commencing 1 November 2017 (one month training prior to market competition). **Customer Management** • Three FTEs in the Service Desk to manage service order exceptions and coordination of activities with various market stakeholders at $7,366 per month per FTE, commencing 1 November 2017 (one month training prior to market competition). • Three FTE internal employees in Customer Relations team to manage increased complaints and claims management processes at $100k per annum per FTE, commencing 1 November 2017 (one month training prior to market competition). **Data Management and Connections activity** • Six FTEs in the Back Office to manage data and network billing exceptions at $7,366 per month per FTE, commencing 1 November 2017 (one month training prior to market competition). **Meter Management** • One FTE internal employee in Metering team to manage notification of meter malfunctions, meter installation test results and auditing and coordination of defects, coordination of meter faults and family failure replacement activity at $130k per annum per FTE, commencing 1 November 2017 (1 month training prior to market competition). **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 2018, 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 2018). **Audit** • Ongoing AEMO audit costs estimated at $25,000 per annum commencing in 2018 based on current audit costs for existing AEMO audits.
Addressing AER reasons for rejection in Preliminary Decision	In its Preliminary Decision, the AER rejected our step changes for the Power of Choice reforms because: • It considered there was uncertainty around the requirements of these reforms;

Name	1a. Power Of Choice Metering Competition
	• It was not satisfied that UE's forecasts reasonably reflect the efficient costs of a prudent operator or a realistic expectation of the cost inputs required to achieve the capex objectives; and • It did not allow any capex because it considered there was uncertainty around the costs – and it wanted to maintain consistency between its decision on opex and capex. The AER noted, however, that: • It would reassess the costs of these reforms should the AEMC make the final rule, and we revise our step change based on the final rule in our RRP; and • If the reforms are not finalised prior to the AER making its Final Decision in April 2016, then we can rely on the regulatory change event or service standard pass through events to recover its costs associated with these rules. We have revised and now re-submit our step change noting that: • The AEMC published its final determination on metering competition on 26 November 2015 clarifying the detailed requirements of these reforms; • We have revisited and revised our forecast capital and operating costs based on the AEMC's final determination as described in this document. We have made every effort to ensure that these revised costs are realistic and reflect the efficient costs of a prudent operator. As described in this document and the related capital resubmission. • To ensure consistency between the capex and opex impacts of these rule changes, we reconsidered, re-estimated and re-submitted our forecast costs for these reforms for both capex and opex as described in the capex section of this RRP and above.

Name	1b. Power Of Choice Customer Access to data					
Amount ($M, Real 2015)	2016	2017	2018	2019	2020	Total
– Regulatory Proposal	0.3	0.3	0.3	0.3	0.3	1.7
– AER Preliminary Decision	-	-	-	-	-	-
– RRP	0.3	0.3	0.3	0.3	0.3	1.8
Legislative / regulatory requirement	On 6 November 2014, the AEMC made a Final Determination on the Consumer Access to Data rule commencing on 1 December 2014 - National Electricity Amendment (Customer access to information about their energy consumption) Rule 2014 No.7 and commencing on 1 September 2015 and 1 March 2016 - National Energy Retail Amendment (Customer access to information about their energy consumption) Rule 2014 No2. Our requirements under the new Rule are therefore both certain and final – although we note that they were also both certain and final when we submitted our Regulatory Proposal to the AER in April 2015. The amendments to the NERR do not apply in Victoria. Victoria has already implemented different data formats for small customer access to interval data. The final rules require AEMO to develop a Meter Data Provision Procedure by 1 September 2015. AEMO published its Final Meter Data Provision Procedure on 1 September 2015. We are required to comply with the new data formats, for all meter types, in accordance with this Procedure from 1 March 2016.					
Services / capability requirements	To comply with the rule change, we need to: • Enable requests for data to be raised by a customer or the customer's authorised representative[115]; • Ensure for each request that there is sufficient information to verify the customer at the premise, verify the customer's relationship with the authorised representative and meet any applicable privacy legislation requirements, including obtaining customers consent for disclosure of confidential information[116]; • Respond to the customer within a certain period of receiving the request[117]; • Provide data formats consistent with the new MDPP[118]; • Make a customer guide available to assist retail customers to understand and interpret detailed interval data formats[119]; and • Implement data management and reporting activities to enable reporting against the obligations. Project Justification PJ15 describes the IT capital project associated with providing the functionality required to support delivery of these services.					
Activities / processes impacted to deliver service	We are expanding our customer portal so that our customers have increased capacity for self-service and timely access to their data The capital project which will expand the existing AMI capability to all meter types, however some types of requests will be delivered more efficiently by manual processes. The AEMC has progressed this reform initiative to empower customers to access their data, assess their energy consumption behaviour and costs and to become engaged in the related services which are expected from smart meters and metering competition. On this basis, the volume of requests can be expected to increase as customers become more engaged and as more sophisticated customer offers and benefits are provided in the form of new services. The business requirements that enable us to achieve compliance with the new Metering Data Provision Procedures and improve customer experience at a summary level include:					

[115] NER 7.7 (a) (7)

[116] NER 7.7 (a1)

[117] AEMO, Meter Data Provision Procedures, 1 September 2015, clause 2.1 (c) to (g)

[118] AEMO, Meter Data Provision Procedures, 1 September 2015, clause 4.2,4.3 and 4.4

[119] AEMO, Meter Data Provision Procedures, 1 September 2015, clause 4.5 (d) (e) – (e)

Name	1b. Power Of Choice Customer Access to data

	• Meter data requests: provide a mechanism for customers and customer authorised representatives to request data.
	• Request administration: establish processes to prioritise, manage and verify requests which are received.
	• Data extract: search for and extract meter data from source systems to fulfil request.
	• Response: generate response files in mandated format and send response to requestor.
	• User guides: provide access to customer guides to understand meter data.
	• Reporting: establish basic volumetrics and compliance operational reporting process to provide visibility for Customer Access to Data process.
	• Data storage and management: establish processes to store customer personal data and response files as per regulatory requirements.
	We have sought additional capability to meet the above requirements to comply with the rule, appropriately verify customers/agents to maintain privacy and confidentiality and to establish ongoing automation and integration of applications.
	Despite improving our capability to respond to requests in an automated fashion, the new rules/procedures:
	• Do not require or limit customers to only requesting data via automated portal facilities, some customers will not wish to register for automated access and may not have access to computer/internet facilities to utilise this option. Some customers may need more manual telephone support;
	• Mean that, where a customer has sought a manual-based process to make a request or may need to make the request manually if the automated system is not able to verify the customer, then increased levels of manual processing will be required to verify the customer, collate data and respond to the customer. For example, clause 3.1(a) of the new procedure requires us to provide paper copies of summary data where requested by the customer;
	• Require bulk requests for Customer Authorised Representatives (CARs) to be individually verified by NMI and responses regarding the failed verification within certain timeframes, where there are large bulk request, the timeframes can be extended by agreement with the CAR. There will need to be a manual intervention to negotiate the timeframes;
	• Mean that any IT systems will need to have support for customers having password or registration issues. There will also be some need for support to assist some customers with technical matters:
	    ○ Opening of csv or zip files;
	    ○ Understanding the file or file naming conventions;
	    ○ Understanding why they may be provided multiple files to cover multiple meter types; and
	    ○ If they are provided these new file formats and then seek to use the Victorian Energy Compare site to explain why the file upload has not worked and to provide a version that would be successful for use in the Victorian price comparator website.
	• Mean that we need to provide support for customer issues/complaints raised and improvements and also to assess any alternate format data requests made (new procedure clause 4.5 (a)) and whether we may need to update its standard minimum format;
	• Cater for the number of individual and CAR bulk data requests varying. We need to manage resources and compliance in relation to response times on failed verification or incomplete details and response times with the required data formats – summary or detailed etc. Management may need to alter resourcing levels to accommodate changed volumes that could arise with changes in retailer pricing and increased focus on energy costs, changes in retail tariff formats or billing detail arising from more cost reflective tariffs, separation of metering charges on retail bills etc.; and
	• Mean that we need to actively consider changes from the minimum format that may improve the way customers consume energy and understand their tariff impacts. We consider that aspects of User Guides and privacy and confidentially concerns will not be static across the five years and will evolve with customer requirements and internal business updates to address privacy and confidentiality.

Name	1b. Power Of Choice Customer Access to data
Cost build-up	The process for calculating 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 $258,000 to support the new system. The assessment of alternative IT solutions to meet the regulatory requirement is presented in the capex submission document 'PJ 19 Project Justification – Power of Choice – Consumer Data Access'.
Addressing AER reasons for rejection in Preliminary Decision	In its Preliminary Decision, the AER rejected our step changes for the Power of Choice reforms because: • It considered there was uncertainty around the requirements of these reforms; • It was not satisfied that our forecast reasonably reflects the efficient costs of a prudent operator or a realistic expectation of the cost inputs required to achieve the capex objectives; and • It did not allow any capex because it considered there was uncertainty around the costs – and it wanted to maintain consistency between its decision on opex and capex The AER noted, however that: • It would reassess the costs of these reforms should the AEMC make the Final Rule, and we revise our step changes based on the final Rule in our RRP; and • If the reforms are not finalised prior to the AER making its Final Decision in April 2016, then we can rely on the regulatory change event or service standard pass through events to recover its costs associated with these Rules. We do not accept the AER's Preliminary Decision to reject its step change based on the uncertainty around the requirements of the reforms at the time of submission. The AEMC published its final determination on 6 November 2014 and we consider there was no uncertainty around the requirements of this reform when we submitted our Regulatory Proposal. Notwithstanding this, we have revised and now re-submit this step change for the following reasons: • We have revisited our forecast capex and opex based on the AEMC's final determination and the AER's rejection of our original proposal and determined that the costs are realistic and reflect the efficient costs of a prudent operator; and • To ensure consistency between the capex and opex cost impacts of the rule change, we have reconsidered, re-estimated and re-submitted its forecast costs for this reform for both capex and opex as described in the capex section of this resubmission and above.

<table>
<tr><td>Name</td><td colspan="6">1d. Power Of Choice Demand Management IT Platform</td></tr>
<tr><td>Amount ($M, Real 2015)</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td><td>Total</td></tr>
<tr><td>– Regulatory Proposal</td><td>-</td><td>-</td><td>-</td><td>0.8</td><td>0.8</td><td>1.6</td></tr>
<tr><td>– AER Preliminary Decision</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>– RRP</td><td>-</td><td>-</td><td>-</td><td>0.8</td><td>0.8</td><td>1.6</td></tr>
<tr><td>Legislative / regulatory requirement</td><td colspan="6">
The Demand Management IT platform will support three rule changes and demand response initiatives:

Trials undertaken under the demand management incentive scheme or the demand management innovation allowance - Rule 2015 No.8;
Collation of data that is needed to meet the AEMO demand side participation information reporting requirements - Rule 2015 No 4; and
Collation of data that may be needed to meet any market information notices issued to us for transmission connection planning data - Rule 2015 No 9.

We discuss these rule changes in turn below.
1. On 20 August 2015, the AEMC issued a final determination on demand management incentive schemes - National Electricity Amendment (Demand management incentive scheme) Rule 2015 No.8.
The new rule requires the AER to develop and publish the demand management incentive scheme and demand management innovation allowance mechanism.
The new rules are aimed at encouraging more efficient expenditure decisions by DNSPs, which may reduce costs to consumers over time. There are two mechanisms under the new framework:

Demand management incentive scheme - the objective of the incentive scheme is to provide DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers.
Demand management innovation allowance – the objective of the innovation allowance is to provide DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance will be used to fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

The key features of the final rule are as follows:

Creation of separate provisions in the NER for a demand management incentive scheme and a demand management innovation allowance mechanism.
Introduction of an objective for the incentive scheme, and a separate objective for the innovation allowance, specifying what these must aim to achieve.
Introduction of a set of principles for the incentive scheme, and a separate set of principles for the innovation allowance, intended to guide the AER in developing and applying these to help achieve their respective objectives.
Requirement for the AER to develop and publish the incentive scheme and innovation allowance in accordance with the distribution consultation procedures, by 1 December 2016.

We have undertaken a number of small scale trials using existing incentive schemes and are committed to progressing these trials on a larger scale, working with governments and regulators, to promote offerings that benefit customers and ultimately network operations and hence all customers. We are location-focussed in these trials, as a means of deferring or avoiding augmentation. A demand response platform will provide a platform for the relevant contracting information and possible demand responses.
2. The AEMC issued a final rule on demand side information on 26 March 2015 - National Electricity Amendment (Improving demand side participation information provided to AEMO by registered participants) Rule 2015 No. 4.
</td></tr>
</table>

Name	1d. Power Of Choice Demand Management IT Platform
	This rule commenced on 26 March 2015. It places an obligation on AEMO in the first instance to develop a demand side participation information guideline by 26 September 2016 and then some three months or more later, registered participants will need to comply with that guideline. Therefore, the earliest effective date of the new rule for us is 1 January 2017. The new rule changes have amended Chapter 3 of the NER, introducing a new rule 3.7D which will eventually apply to all registered participants (including competitive MC's). Key features of the new rule are that: • Registered participants will be required to provide to AEMO information on DSP, in accordance with DSP information guidelines (Guidelines). AEMO must take into account that information when developing or using load forecasts for the purposes of the exercise of its functions under the Rules; • AEMO will be required to develop and amend the Guidelines, having regard to registered participants' reasonable costs of efficient compliance with the Guidelines compared to the likely benefits from the use of the information in forecasting load for the purposes of the exercise of its functions under the Rules; • When developing and amending the Guidelines, AEMO will be required to consult with the following persons in accordance with the NER consultation procedures: o Registered participants; and o Persons who, in AEMO's reasonable opinion, have, or have identified themselves to AEMO as having, an interest in the Guidelines (referred to in this summary as interested stakeholders) • AEMO will be required to publish details, no less than annually, on the extent to which, in general terms, the information it has received under the final rule has informed the development or use of its electricity load forecasts for the purposes of the exercise of its functions under the NER; and • It defines the scope of information that AEMO may specify must be provided to it by registered participants under the Guidelines. The guideline will require registered participants to provide AEMO with: • Contracted demand-side participation (e.g. agreement to non-scheduled load curtailment or the provision of unscheduled generation in certain circumstances). Unscheduled generation is any generation which is not scheduled or semi-scheduled under the NER. The final rule confirms that this includes generation which is exempt from registration i.e. solar or micro wind for example. The guideline can also require any other load curtailment or provisions of unscheduled generation that is in response to demand or price. This appears to capture a customer demand response from a critical peak tariff for example; • The circumstances where the load curtailment or generation may be provided, the location, the quantity and any historical or current information; • When information must be provided and updated e.g. every year or five minutes to meet dispatch; and • Data in a certain format and any other information that AEMO requires to assess accuracy of information. As a registered participant, we will have the obligation to provide the information in the formats required by AEMO. As we gain more contracted demand across a range of initiatives, it will be important to collate the information on contracts, contracts terms and the nature/size of the response. Understanding the level and location of all contracted demand is equally important to us for network planning purposes and network operations. We consider that as this area increases in volume and complexity it is important that we have an IT platform to collate and understand the information and link into our other network systems. ***3. AEMC issued a final rule determination on 22 October 2015 - National Electricity Amendment (AEMO access to demand forecasting information) Rule 2015 No. 9.*** The rule explicitly recognises demand forecasting at a connection point and regional level as a National Transmission Planner function in the NER and AEMO's ability to compel persons to provide connection point data and information to prepare demand forecasts using its information gathering powers in the NEL, namely market information orders and market information notices. The rule became effective on 22

Name	1d. Power Of Choice Demand Management IT Platform
	October 2015 although AEMO's obligation to publish the forecast and data does not commence until 1 July 2016. If requested, we will be required to complete the market information notices to aid in the collation of network data which may assist in the planning of a transmission connection point.
Services / capability requirements	We are committed to providing and deploying non-network alternatives to traditional network investment where this is more cost effective for the customer. During the 2011 to 2015 regulatory period, we have engaged over 800 customer and service providers in both trial and business as usual demand management schemes. The Demand Management IT platform provides the capability to deploy non-network options to meet the demand for SCS in the most cost effective manner. Without a demand management IT platform, it is not cost effective to widely deploy or report on the performance of non-network options. Although this project will provide the capability to participate in the new incentive scheme (NER clause 6.6.3), the project is financially justified on reducing the future requirement of network capital. This justification is based on current incentives and the expected increased deployment of non-network options once further incentives are introduced. The demand management IT platform will provide the following capabilities: Managing Demand Management Programs: • Develop processes and capabilities to support demand response programs directly with consumers or through third party aggregators; • On-going management of consumers who are enrolled in a demand management program; and • On-going asset management of devices that will be used for direct control of demand. Managing a Demand Response Event: • Create Customer baseline calculation and settlement data; • Optimize demand response (DR) dispatch for cost, contract, decay and snap-back; • Create DR events and notify participants, directly or through a third party aggregator; • Manage devices via existing load management systems (including UE and customer owned devices and via multiple channels (DMS/SCADA, AMI network, internet or other); • Facilitate timely notification of DR event by integrating with third party aggregators. The current practice of manually entering data into the 3rd party aggregator's portal will not be sustainable as the number of participants increase; • Monitor customer event participation; and • Provide business and AEMO reporting.
Activities / processes impacted to deliver service	The operating cost is for software and hardware maintenance and for application support for the Demand Management IT platform.
Cost build-up	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); and • 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 SCS Opex Step Change of $0.8 million per annum.

Name	1d. Power Of Choice Demand Management IT Platform
Addressing AER reasons for rejection in Preliminary Decision	In its Preliminary Decision, the AER rejected our step changes for the Power of Choice reforms because: • It considered there was uncertainty around the requirements of these reforms; • It was not satisfied that UE's forecasts reasonably reflect the efficient costs of a prudent operator or a realistic expectation of the cost inputs required to achieve the capex objectives; and • It did not allow any capex because it considered there was uncertainty around the costs – and it wanted to maintain consistency between its decision on opex and capex. The AER noted, however, that: • It would reassess the costs of these reforms should the AEMC make the final rule, and we revise its step changes based on the final rule, in the RRP; and • If the reforms are not finalised prior to the AER making its Final Decision in April 2016, then we can rely on the regulatory change event or service standard pass through events to recover its costs associated with these rules. We have revised and now re-submit this step change for the reasons set out below: • The AEMC has published final determinations on the rules that this step change delivers on; • We have revisited and revised our forecast capital and operating costs based on the AEMC's final determinations as described in this document. We have made every effort to ensure that these revised costs are realistic and reflect the efficient costs of a prudent operator. As described in this document and the related capital resubmission; • We expect energy affordability to be a continuing issue for customers and as such expect that there will be increasing levels of demand response as service providers offer solar/batteries and other forms of load control; and • To ensure consistency between the capex and opex cost impacts of these rule changes, we have reconsidered, re-estimated and re-submitted our forecast costs for these reforms for both capital and operating expenditure as described in the capex section of this resubmission and above.

Name	2. Regulatory Information Notice Reporting					
Amount ($M, Real 2015)	2016	2017	2018	2019	2020	Total
– Regulatory Proposal	-	0.4	0.4	0.4	0.4	1.6
– AER Preliminary Decision	-	-	-	-	-	-
– RRP	0.2	1.3	1.7	0.7	0.7	4.6
Legislative / regulatory requirement	The RIN for the Category Analysis information requires that Actual Information be provided from 2016. To achieve this, we will need to address data issues with 343 items of reported information. Currently, one item of Repex information (transformer replacement capacity) is reported as Estimated Information, but a significant number of items (about 340) rely on the correct allocation of costs and other attributes, and accurate estimation to meet the RIN definition for Actual Information. The potential for misallocation or inaccuracies in the data is such that we may not be able to provide Actual Information in all future years. Current data issues in Category Analysis RIN template 2.2.1 include: • Operating voltage is not recorded for poles, pole top structures, overhead conductors, underground cables, service lines, transformers, and switchgear; • Material type is not recorded for poles; • Number of phases is not recorded for overhead conductors and transformers; • Customer type and connection complexity is not recorded for service lines; • Ampere rating is not recorded for transformers; • Asset type is not recorded for public lighting; and • Function is not recorded for SCADA, network control and protection systems. Current data issues in Category Analysis RIN template 2.2.2 include: • Feeder type is not recorded for poles, overhead conductors and underground cables; and • Total MVA replaced and disposed is not recorded for transformers. Currently, the RIN information for these items is prepared using related information (primarily work orders) to allocate the actual expenditures to volumes of assets installed, replaced and failed. The current allocation process has meant diverting staff away from their business-as-usual activities. While this has been possible in past years by prioritising work, a continuation of this approach in the longer term is not sustainable as deferred activities must be undertaken. Additional opex of $1.5 million per annum would be required to retain the current allocation approach, with no guarantee that Actual Information could be provided in all years due to the lack of robustness inherent in this approach. As the opex costs required to address these issues are supporting new regulatory requirements they are not included in our 2014 base opex. The proposed works support the National Electricity Rule (NER) opex objective relating to regulatory compliance; "6.5.6(a)(2) - comply with all applicable regulatory obligations or requirements associated with the provision of Standard Control Services".					
Services / capability requirements	Three options to reliably report Actual Information were evaluated, including revising our IT systems to enhance RIN reporting, a dedicated RIN reporting solution to remove the estimated component of the current allocation process and a risk based enhancement of our IT systems that carries some risk that inaccuracies may occur such that Actual Information may not be reported in every year. The third option is preferred on a least cost basis considering both capex and opex requirements. The preferred solution will require us to make changes to our IT systems, the IT systems used by our service providers and to support these changes with on-going maintenance activities.					

<table>
<tr><th>Name</th><th>2. Regulatory Information Notice Reporting</th></tr>
<tr><td>Activities / processes impacted to deliver service</td><td>
A full description of the proposed changes to our systems and processes is set out in the capex section of this Revised Regulatory Proposal and in justification paper PJ22 RIN Reporting. The preferred option includes enhancements to the reporting capabilities of:

The existing asset and financial source systems, including implementation of the functionality provided by SAP HANA and SAP Works Manager
Current RIN reporting suite
Our data warehouse and reporting / analytics required for RIN.

The opex required to support the proposed changes, includes:

Changes to service providers systems – the efficiency of our work processes relies on our service providers' systems being seamless with our own. The new data required for RIN reporting will largely originate from our service providers so changes to our systems must be reflected into their systems for the change to be effective. As the required expenditures are not to an asset owned by us, they are expensed rather than capitalised;
Additional support and licence costs – on-going application support and maintenance licences for SAP HANA and SAP Works Manager are required under the preferred option (this does not include purchase of the licences, which are capitalised); and
Additional staff for managing data quality – improvements in the quality assurance processes will be required to ensure acceptable data quality for RIN reporting is maintained, particularly for data originating from our service providers that is not otherwise used by United Energy and hence is not currently quality checked.

The changes must also align with other strategic IT projects that are proposed for the 2016-2020 period. We have in place two improvement projects that are intended to provide for improved asset management information and analytics. These are:

The mobility project that allows the capture and population of asset information
The Asset Management Capability System.

Both of these projects will change the level and detail of asset information and that will impact on the way information is reported under the Category Analysis RIN. The opex proposed for RIN Reporting relies on these projects proceeding.
</td></tr>
<tr><td>Cost build-up</td><td>
The basis of the proposed opex is set out below.
Changes to service providers systems are based on the minimum work to reflect the changes to our systems. The systems affected are JSAP – Zinfra SAP system and Downer JDE – JD Edwards ERP System. The IT labour required is set out in the following table as $0.60 million in 2017 and $1.0 million in 2018. The timing of the works is to suit the implementation of changes to our IT systems. Unit costs of $100,000 per IT labour resource is an expected average for the type of resource sought.
<table>
<tr><th>Resource Requirement</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>Total</th></tr>
<tr><td>JSAP Maintenance Management Integration Specialist</td><td></td><td>1</td><td>1</td><td></td><td></td><td>2</td></tr>
<tr><td>JSAP Maintenance Management Specialist</td><td></td><td>1</td><td>1</td><td></td><td></td><td>2</td></tr>
<tr><td>JSAP Maintenance Management Configuration Consultant</td><td></td><td>1</td><td>1</td><td></td><td></td><td>2</td></tr>
<tr><td>JSAP Technical Writer</td><td></td><td></td><td>1</td><td></td><td></td><td>1</td></tr>
<tr><td>JSAP Test Manager</td><td></td><td></td><td>1</td><td></td><td></td><td>1</td></tr>
<tr><td>JD Edwards Maintenance Management Integration Specialist</td><td></td><td>1</td><td>1</td><td></td><td></td><td>2</td></tr>
<tr><td>JD Edwards Maintenance Management Specialist</td><td></td><td>1</td><td>1</td><td></td><td></td><td>2</td></tr>
<tr><td>JD Edwards Configuration Consultant</td><td></td><td>1</td><td>1</td><td></td><td></td><td>2</td></tr>
<tr><td>JD Edwards Technical Writer</td><td></td><td></td><td>1</td><td></td><td></td><td>1</td></tr>
<tr><td>JD Edwards Test Manager</td><td></td><td></td><td>1</td><td></td><td></td><td>1</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>TOTAL FTE</td><td>0</td><td>6</td><td>10</td><td>0</td><td>0</td><td>16</td></tr>
<tr><td>TOTAL IT labour cost ($m)</td><td></td><td>0.60</td><td>1.00</td><td></td><td></td><td>1.60</td></tr>
</table>
</td></tr>
</table>

Name	2. Regulatory Information Notice Reporting
	Additional support and licence costs are based on current market rates representing $0.15 million in 2016 and $0.65 million per annum from 2017. Additional staff for managing data quality is estimated at 0.5 FTE from 2016 at a cost of $0.05 million per annum. The effort is based on assessing data quality across 53 data categories (overhead lines and services) from approximately 10,000 work orders per annum (representing a forecast of approximately 11,000 services replaced and 24 km of conductor replaced per annum in the 2016 to 2020 regulatory period). A review time per work order averaging 5 minutes has been used. This cost will not be required when future changes required for asset management purposes are made to our asset information systems (after 2020), including conductor and service information.
Addressing AER reasons for rejection in Preliminary Decision	The AER stated that as the proposed step change in opex depends on the forecast increase in capex (which the AER disallowed), it has also not included the step change in our opex forecast. In our view, maintaining the current reporting processes cannot be achieve at historical costs as staff who have been diverted to RIN reporting must complete deferred planning and asset management works within a reasonable timeframe. We estimate that an additional opex of $7.5 million ($1.5 million per annum) would be required, with no guarantee that Actual Information could be provided in all years due to the lack of robustness in the current RIN reporting processes based on allocation. In this RRP, we have increased our step change in opex by $3 million (from $1.6 million to $4.6 million for the 2016 to 2020 regulatory period) to achieve a reduction in capex of $9.6 million (from $24.3 million to $14.7 million) through adopting a risk based approach to RIN reporting. We have calculated that the proposed step change results in the lowest net present cost of the options evaluated.

<table>
<tr><th>Name</th><th colspan="6">3b. Energy Safe Victoria rule changes</th></tr>
<tr><th>Amount ($M, Real 2015)</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>Total</th></tr>
<tr><td>– Regulatory Proposal</td><td>1.7</td><td>1.7</td><td>1.7</td><td>1.7</td><td>1.7</td><td>8.7</td></tr>
<tr><td>– AER Preliminary Decision</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>– RRP</td><td>2.3</td><td>2.3</td><td>2.3</td><td>2.3</td><td>2.3</td><td>11.7</td></tr>
<tr><td>Legislative / regulatory requirement</td><td colspan="6">
The new Electricity Safety (Electric Line Clearance) Regulations 2015 (2015 ELC Regulations) were finalised on 28 June 2015. They replaced the Electricity Safety (Electric Line Clearance) Regulations 2010 (2010 ELC Regulations). On 27 November 2015, Energy Safe Victoria (ESV) issued Guidance Information on the Regulations (copy attached).
The key changes to the Regulations are as follows:
Clause 9 – Application of AS 4373
This is a new obligation that requires us to cut a tree in accordance with AS 4373. Our obligation is qualified by the words “as far as practicable”. Compliance with AS 4373 prohibits cutting practices, such as lopping and topping, mechanical cutting and the use of climbing spurs.
Clauses 15 and 16 - Notifications
<u>Clauses 15 (1)(a), (3)(a),(5)(a), 15 (1)(b),(3)(b),(5)(b) and 15(1)(a),(1)(b),(3)(c),(5)(c)</u>
There are two new obligations to give a notice to a private landowner about a tree on its private land and to a council about the council’s trees.
The notice must be given to the owner or occupier of any contiguous private property if the use of that property may be affected during the cutting or removal of the tree.
The content of the notice was not specified at all under the 2010 ELC Regulations. Under the 2015 ELC Regulations, a notice must include:

Contact details of the responsible person;
Details of the intended cutting or removal; and
Advice about dispute resolution procedures.

For trees on private land, a notice must also include details of the consultation procedure, details of whether the tree is of cultural or environmental significance (CES) or of ecological, historical or aesthetic significance (EHAS). The notice must also include a diagram that shows the tree, where the electric line is and where the tree is to be cut. In addition, for council trees, the notice must include whether the tree is on public land, or is of CES, or is of EHAS. For trees on land contiguous to private land, the notice must include details of the impact that the intended cutting or removal may have on the affected person’s use of their land during the cutting or removal.
<u>Clause 15(6) and (7)</u>
A notice must be given before the cutting or removal is to occur. It now must state the day on which, or a period during which, the cutting or removal is intended to commence.
<u>Clause 16</u>
There is now a requirement to publish a notice in a newspaper circulating generally in the locality of the land in which the tree is to be cut or removed. Previously, the notice requirement only applied to adjacent landholders and if a written notice was given a newspaper publication was not also required. A newspaper notice is now required for cutting or removing trees on public land.
Division 4 of Part 2 – Assistance to Councils and others
This Division introduces a new requirement to advise a Council, upon request, to determine the additional distance for sag and sway required under Part 3, and provide greater assistance to local councils, private property owners and occupiers to facilitate more effective clearing of the vegetation.
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</table>

Name	3b. Energy Safe Victoria rule changes
	ESV's recent ELC audits have recommended that we provide greater assistance to local councils, private property owners and occupiers to facilitate more effective clearing of vegetation.
Services / capability requirements	The new obligations set out above require us to provide additional services or capabilities. **Application of AS 4373** We must cut trees in accordance with AS 4373, as far as practicable – this may involve new or different cutting practices. However, the guidance information from ESV is that we will be able to continue vegetation management using existing industry practices. As part of AS4373, a Certificate 3 Arborist is required for tree inspections. **Notification** The guidance information from ESV confirms that we must notify more customers, provide more information, and meet new consultation requirements for customers. In addition to notifying individual customers, we must publish notices in local newspapers. **Assistance to councils and others** We must provide greater assistance to Councils, and private property owners and occupiers, in particular the provision of advice on vegetation management, the safe limits of approach, the safe methods for cutting and removal of trees and determining the allowance for sag and sway.
Activities / processes impacted to deliver service	The new obligations set out above require us to undertake new activities and processes. **Application of AS 4373** Historically, there has been no requirement to engage a Certificate 3 Arborist for tree inspection. AS4373 requires a Certificate 3 Arborist to undertake inspections. This will require additional training for our six arborists and increase our salary costs. **Notification** Historically, we have only provided: • Notices to the directly affected person(s). Providing notices to contiguous properties will potentially increase the number of notices per site, from one to four; • A generic picture with each notice, based on the picture in the ELC regulations. Providing a specific image of each tree, the location of the electric powerline, and indicating where the tree will be cut will, reduce tree inspection and notification productivity by about 80 per cent, quadrupling costs. ESV guidance information confirms that each notice needs to comply with the regulations and include the specified information. Notices will now need to be placed in the local newspapers, on a weekly basis, to advise the public of the intended cutting areas and the dates when cutting may take place. We will need to place these notices in the 12 local newspapers circulating our area. **Assistance to councils and others** We will need to employ additional resources in order to provide greater advice and assistance to Councils, and private property owners and occupiers, on vegetation management, the safe limits of approach, the safe methods for cutting and removal of trees and determining the allowance for sag and sway.
Cost build-up	**Application of AS 4373** The requirement for a Certificate 3 Arborist qualification will increase salary costs by $15,000 per year per tree inspector. This equates to $90,000 per year for our six inspectors. This will increase the cost of tree inspection by $0.45 million over five years. **Notification** At a meeting with us on 9 November 2015, ESV confirmed that they expected us to comply with the new notice requirements, including providing a notice in local newspapers. This was later confirmed in the ESV guidance information.

Name	3b. Energy Safe Victoria rule changes
	A half page advertisement in a local newspaper will cost $1,400 per week per paper. This equates to $16,800 per week for the 12 local newspapers. Given that we cut trees for about 40 weeks of the year, this equates to $672,000 per annum. We will also require a full time resource to manage this activity at a cost of about $160,000 per year. This will increase the cost of notification by $4.16 million over five years. Although the other new notification obligations will require us to deliver four times as many notices, each including more detailed information, we are not seeking additional funding for this. Instead, we will pursue innovative ways to minimise our costs within our opex base year allowance. **Assistance to councils and others** The new regulations require us to provide greater advice and assistance to Councils on vegetation management, the safe limits of approach, the safe methods for cutting and removal of trees and determining the allowance for sag and sway. Recent ESV ELC audits have recommended that we provide greater assistance to local councils, private property owners and occupiers to facilitate more effective clearing of the vegetation. This is evidenced in the attached ESV July 2015 report entitled "Safety Performance Report on Victorian Electricity Networks 2014" – refer especially to page 45. The time involved in providing assistance and the required sag and sway information will require us to employ an additional two persons at about $160,000 per person per year. The cost of assisting councils, private property owners and occupiers to facilitate more effective clearing of vegetation, will generally involve us cutting the trees and cost about $1.1 million per annum. This will increase the cost of assisting Councils and others by $7.1 million over the five year regulatory period.
Addressing AER reasons for rejection in Preliminary Decision	The AER did not accept our step change in its Preliminary Decision because the 2015 ELC Regulations were not finalised when we submitted our Regulatory Proposal, and ESV's Guidance Paper had not yet been issued. The AER requested that we submit a revised step change proposal in our RRP. We have prepared this revised step change based on the Electricity Safety (Electric Line Clearance) Regulations 2015, ESV's November 2015 Guidance Paper, the ESV's report "Safety Performance on Victorian Electricity Networks 2014" and meetings between ourselves, the AER and the ESV. The ESV concluded that the 2015 ELC Regulations had marginally increased some responsibilities. This conclusion was based on the draft regulations, and did not include the costs associated with the additional obligations included in the final 2015 ELC Regulations: • The application of AS 4373; • Notification; and • Assistance to councils and others.

UNITED ENERGY

Name	4b. Stakeholder engagement					
Amount ($M, Real 2015)	2016	2017	2018	2019	2020	Total
Regulatory Proposal	0.3	0.3	0.3	0.3	0.3	1.3
AER Preliminary Decision	-	-	-	-	-	-
RRP	0.3	0.3	0.3	0.3	0.3	1.3
Legislative / regulatory requirement	This step change arises from the 2012 rule change that requires DNSPs to demonstrate that their capex and opex address the concerns of consumers, as well as the Consumer Engagement Guideline that the AER issued as part of its Better Regulation Reform Program. The AER's Consumer Engagement Guideline notes: • "One key focus of the AEMC's rule changes and government reforms is improving service providers' engagement with their consumers" (page 5); • "Overall, we expect service providers to adopt the guideline to build a robust consumer engagement strategy and processes" (page 6); • "our guideline provides a framework for service providers to establish a consumer engagement strategy and processes that best fits their business" (page 7); and • "Implemented properly, the guideline may require most service providers to significantly change how they run their businesses. We expect service providers, helped by the guideline, to develop and implement strategies for consumer engagement to occur in a more systematic and strategic way" (page 8).					
Services / capability requirements	The 2012 changes to the NER 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 2016 to 2020 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.					
Activities / processes impacted to deliver service	A significant number of projects are planned for the 2016 to 2020 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; and • Undertake community consultation activities associated with capital projects. Facilitate demand management programs from community engagement through to customer fulfilment.					
Cost build-up	Costs of employing two specialists to undertake on-going stakeholder engagement in the 2016 to 2020 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. These costs are on-going, as they relate to our need to increase and improve our engagement with stakeholders throughout the 2016 to 2020 regulatory period.					

Name	4b. Stakeholder engagement
Addressing AER reasons for rejection in Preliminary Decision	The AER's Preliminary Decision rejected our proposed step change because it considers that it "consider(s) a prudent service provider would already be undertaking the level of consumer engagement commensurate with the rule requirements and so would not need an increase in its forecast total opex". This view is inconsistent with the expectations set out in the Consumer Engagement Guidelines that "Implemented properly, the guideline may require most service providers to significantly change how they run their businesses". We accept the need to change our operations, but consider that additional resourcing is essential to enabling us to do this. We are not currently resourced to effectively meet stakeholder engagement requirements throughout the 2016 to 2020 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 2011 to 2015 regulatory period, we have focussed on enhancing our Customer Consultative Committee and incremental improvements on communication on our capital projects and new initiative, such as our summer energy demand trial. In order to deliver more comprehensive stakeholder engagement, additional specialist resources are required. We have based this step change on two full-time resources being employed from the start of the 2016 to 2020 regulatory period on an on-going basis.

<table>
<tr><th colspan="2">Name</th><th colspan="6">7a and 7b – Neutral Testing and Network Planning and Analytics (Both related to IT "PJ12 - Network Analytics" Business Case)</th></tr>
<tr><th colspan="2">Amount ($M, Real 2015)</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>Total</th></tr>
<tr><td rowspan="2">– Regulatory Proposal</td><td>7a</td><td>0.0</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.4</td></tr>
<tr><td>7b</td><td>-</td><td>-</td><td>0.8</td><td>1.2</td><td>2.1</td><td>4.1</td></tr>
<tr><td rowspan="2">– AER Preliminary Decision</td><td>7a</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>7b</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td rowspan="2">– RRP</td><td>7a</td><td>0.0</td><td>0.57</td><td>0.57</td><td>0.57</td><td>0.57</td><td>2.3</td></tr>
<tr><td>7b</td><td>0.0</td><td>0.0</td><td>0.8</td><td>1.2</td><td>2.1</td><td>4.1</td></tr>
<tr><td colspan="2">Legislative / regulatory requirement</td><td colspan="6"><u>7a – Neutral testing</u>

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.

The costs associated with this step change are on-going, as they relate to complying with this regulatory obligation. 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.

<u>7b – Network Planning and Analytics</u>

This involves providing 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 SCS.</td></tr>
<tr><td colspan="2">Services / capability requirements</td><td colspan="6"><u>7a – Neutral testing</u>

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.

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.

We commenced our inspections in 2009 as part of our AMI 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.

<u>7b – Network Planning and Analytics</u>

This will enable us to maintain the quality, reliability and security of the supply of SCS.</td></tr>
<tr><td colspan="2">Activities / processes impacted to deliver service</td><td colspan="6"><u>7a – Neutral testing</u>

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</table>

Name	7a and 7b – Neutral Testing and Network Planning and Analytics (Both related to IT "PJ12 - Network Analytics" Business Case)
	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; and • Approximately 300 individual site visits per annum to investigate detected issues. *7b – Network Planning and Analytics* This will enable us to perform analysis of network operational data from AMI meters and other data monitoring and data collection devices to inform network maintenance and capital investment programs. This will avoid increased network Opex by removing the need for manual neutral integrity testing for all connections points on our network.
Cost build-up	*7a – Neutral testing* 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 AMI program. The annual cost of $0.57 million from 2017 to 2020 is made up of: • 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. *7b – Network Planning and Analytics* The capex and opex for the Network Planning and Analytics project are outlined in 'PJ12 Project Justification – Network Analytics'. The Opex step change comprises: • Hardware maintenance and support of $1.485 million based on 20 per cent of the original hardware purchase price per annum; • Software maintenance of $2.178 million based on 22 per cent of original software purchase price per annum; and • Application support of $0.48 million 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.
Response to AER's arguments for rejecting step change	*7a – Neutral testing and 7b – Network Planning and Analytics* These two step changes complement the capex for IT "PJ12-Network Analytics" that the AER approved in its Preliminary Decision, which automates neutral integrity testing for all AMI metered service mains. The AER rejected our proposed: • Neutral testing step change on the basis that it is not prepared to consider individual costs as part of the Base-Step-Trend opex assessment; and • Network planning and analytics step change on the basis that there is not a change in regulatory obligation but rather is required to enable us to maintain our current services and avoid increased opex. We do not accept the AER's positions because: • The costs associated with these step changes are not included in the Opex base year as the AER has presumed in its Preliminary Decision • We have a clear regulatory obligation to undertake neutral testing;

Name	7a and 7b – Neutral Testing and Network Planning and Analytics (Both related to IT “PJ12 - Network Analytics” Business Case)
	• The costs of meeting our obligations have historically been covered under AMI CROIC, which is not a SCS. These costs are therefore both required for regulatory purposes and are incremental to our historical SCS costs. They should therefore be treated as an opex step change.

<table>
<tr><th>Name</th><th colspan="6">9 – IT Security Costs</th></tr>
<tr><th>Amount ($M, Real 2015)</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>Total</th></tr>
<tr><td>– Regulatory Proposal</td><td>0.7</td><td>0.8</td><td>0.8</td><td>0.8</td><td>0.8</td><td>4.0</td></tr>
<tr><td>– AER Preliminary Decision</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>– RRP</td><td>0.7</td><td>0.8</td><td>0.8</td><td>0.8</td><td>0.8</td><td>3.9</td></tr>
<tr><td>External requirement</td><td colspan="6">This step change relates to spending on ICT security resources and services to counter external threats and risk to our network. 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 including putting life at risk.</td></tr>
<tr><td>Services / capability requirements</td><td colspan="6">Based on our internal security reviews, supported by much external evidence, consumer concerns and comparisons with other similar organisations, we have determined that the proposed IT security program is essential to increase our security maturity.

For example, in recent months, the Bureau of Meteorology (BOM), a Government agency, has been the subject of cyber terrorism. We consider that the threat of such attacks is increasing. The risks associated with these sorts of attacks are different with the higher integration of technology into the network at the low voltage level. We are conscious that these sorts of attacks are evolving and changing constantly.

This step change is aimed at proactively mitigating (amongst other cyber security events) a cyber-terrorism event, limiting any damage and service restoration costs that might be caused by such an event.</td></tr>
<tr><td>Activities / processes impacted to deliver service</td><td colspan="6">The IT Security Program involves a range of operational activities and strategic projects that include:
• Process changes;
• Upgrading / updating security products (hardware and software);
• Implementing new software and hardware products to address current weaknesses;
• An independent, specialist security organisation has been engaged, through a competitive tender process, to both deliver and continue to support the program.

These activities and strategic projects are described in the PJ23 – Security Program Project Justification, which was submitted with our Regulatory Proposal.</td></tr>
<tr><td>Cost build-up</td><td colspan="6">The IT Security Program, as described in the PJ23 – Security Program Project Justification, has been developed after a thorough review of our current security capabilities and following the KPMG independent assessment of UE's security maturity in October 2014.

The programme costs have been calculated, with consideration of current and emerging security threats and the solution options available in the market to determine the best fit for us. The operating costs described above are an essential outcome of the program and critical to its success.</td></tr>
<tr><td>Response to AER's arguments for rejecting step change</td><td colspan="6">We do not accept the reasons that the AER gave in its Preliminary Decision for rejecting our proposed step change:

<u>Reason 1 – Security monitoring is a discretionary business decision</u>

The AER accepted our proposed IT security capex program but rejected the associated opex step on the basis that "The level and form of IT security monitoring United Energy undertakes is a discretionary business decision" and that "United Energy has not demonstrated to us why this program could not be funded through other reductions in discretionary expenditure".

We consider that the escalating risk, external expectations and consumer concerns regarding both the security of customer information and the integrity of the distribution network make IT security more than a</td></tr>
</table>

Name	9 – IT Security Costs
	discretionary business decision. There is substantial evidence indicating that global companies and Australian businesses, including ourselves, are operating in an environment where IT security threats are escalating. The following three references provide specific highlights on the ever growing threat and demands on Australian organisations in relation to IT security: • *Reference #1: 2015 Australian Cyber Security Centre Threat Report* - In July 2015, the Australian Cyber Security Centre issued the first ever unclassified security threat report based on the Australia. The report noted the Governance's national Computer Emergency Response Team (CERT) has responded to 11,073 cyber security incidents in 2014, 153 of which involved systems of national interest, critical infrastructure and Government. The Energy sector ranked number 1 on the chart for reporting majority (29%) of the incidents to the Australian Government in 2014. We consider that this is a clear indication that cyber security threats are on the rise and that we must respond accordingly to this increasing threat by lifting our security maturity. The report also provided an outlook on the trends for 2015 and beyond predicting that the number of state and cyber criminals with destructive capability will increase. This report is available at: *https://www.acsc.gov.au/publications/ACSC_Threat_Report_2015.pdf* • *Reference #2:PwC's 2016 Global State of Information Security Survey* - In October 2015, PwC released its 2016 Global State of Information Security Survey Report, which is a global study with more than 10,000 participants across various sectors. This report allows companies to benchmark and validate their state of information security against other organisations on a national and global level. The report highlighted that in Australia 59% of companies have boosted their security budget to combat the increasing threat, with the security spend of overall IT budget of around 4.02%. The report also validated that there has been a 105% increase in the number of detected security incidents in Australia over the last 12 months. The proposed IT security program opex of $4M represents 2.6% of our overall IT Opex budget. Therefore, whilst it is in line with the industry trend for increasing IT security spend, it is substantially below the 4.02% quoted in PWCs report. We note that in their 2015 Global State of Information Security Survey, PWC indicated that the average security spend for the Power and Utilities sector in 2014 was 3.9% of overall IT budget. The PwC report is available at: *http://www.pwc.com.au/publications/global-information-security.html* • *Reference #3: ASIC Report 429 – Cyber resilience: Health check* - ASIC published its Report 429 'Cyber resilience: Health check' on 19 March 2015. ASIC has provided helpful guidance to businesses in bolstering their own cyber resilience and has highlighting cyber risk management as a potential matter of regulatory compliance. ASIC defines cyber resilience as "the ability to prepare for, respond to and recover from a cyber-attack". The Report emphasises the importance of cyber resilience in protecting the integrity of global markets and supporting consumer trust and confidence. Our Security Strategy, once implemented, will enable us to improve cyber resilience and manage cyber risks in compliance with ASIC requirements. The ASIC report is available at: *http://asic.gov.au/regulatory-resources/find-a-document/reports/rep-429-cyber-resilience-health-check/* Based on the above references, we consider that the requested IT Opex step change for security is a prudent and efficient, non-discretionary spend to protect consumers, retailers and other market operators from the security risks and meet both internal and external expectations. *Reason 2 – The IT Security step change should be funded without expenditure increases* The AER states that "We would typically consider a service provider should be able to fund increases in discretionary opex without forecasting an increase in total opex". We do not consider the IT security step change can be met from the base year opex. This is because, for the reasons discussed above, we consider that there is a fundamental increase in the security risk that we need to address that will require us to acquire additional capability in the 2016 to 2020 regulatory period. We also do not consider the that IT security step change can be met from the rate of change allowance because it does not cover exogenous events such as a changed security environment, but rather relates to incremental growth in the network.

Name	12. New pricing obligations					
Amount ($M, Real 2015)	2016	2017	2018	2019	2020	Total
– Regulatory Proposal	-	-	-	-	-	-
– AER Preliminary Decision	-	-	-	-	-	-
– RRP	1.2	0.5	0.3	0.3	0.3	2.5
Legislative / regulatory requirement	This step change relates to costs associated with the AEMC's Distribution Network Pricing Arrangements rule change that was made on 27 November 2014, which created a new pricing framework and a new set of obligations for us relative to the previous pricing rules. The intent of the rule change is to drive cost reflective network pricing and to improve the transparency of DNSPs' pricing information. The network pricing rule change requires us to set prices that reflect the efficient cost of providing network services to individual consumers. We need to develop a tariff structure statement (TSS) and to consult with consumers on its development. We submitted a proposed TSS to the AER by 25 September 2015. Prices based on the new set of pricing principles will apply in Victoria from 1 January 2017. We are therefore seeking this step change for the same reasons that the AER allowed in its Preliminary Decision that approved a step change for Jemena.					
Services / capability requirements	The AEMC's Distribution Network Pricing Arrangements rule change introduces new obligations on DNSPs to: • Comply with new network pricing objective and principles: o Tariff should reflect the efficient costs of providing the service to the customer; o Each tariff must be based on the LRMC having regard to a number of factors; o Revenue from each tariff must reflect the efficient costs of servicing the customers on that tariff, when summed equal to total revenue allowance and minimise the distortions from efficient usage patterns; o Assess the impact of new tariff on customers based on the year on year price impact; o Ensure that tariffs structures are reasonably capable of being understood by retailer customers; and o Comply with all jurisdictional obligations. • Produce a TSS, including: o Tariff classes into which retail customers will be divided; o Policies and procedures for assigning network customers from one tariff to another; o The structure of each tariff proposed; o The charging parameter for each tariff proposed; o The approach to setting the tariffs; • Prepare an indicative pricing schedule to accompany the TSS setting out the indicative pricing levels for each tariff throughout the period; and • Consult with customers and stakeholders on the development of the tariff structures included in the TSS.					
Activities / processes impacted to deliver service	The additional obligations raise our costs of providing services to customers in the following ways: • Customer communication and education: o We, in conjunction with other energy market participants, will need to educate customers on the new tariff and implication; o We need to advise customer of the assignment to the new retail tariff;					

Name	12. New pricing obligations
	○ We need to provide additional ongoing call centre support for the new tariff; and ○ We need to provide additional ongoing retailer and stakeholder support. • Assessment of customer impacts: ○ We need to assess the impact of changes in tariffs on customers, which will involve additional detailed modelling. • Customer consultation: ○ We require a sustained increase in customer consultation to ensure that customer impact principles are appropriately managed in future TSS. • Preparation of the TSS and associated documentation: ○ We need to prepare an additional regulatory submission for the TSS, which needs to be supported by detailed analysis. While we await the approval of our tariffs we now have a much clear understanding of the work involved in transitioning customers to cost reflective network tariffs than we had at the time that we submitted our Regulatory Proposal.
Cost build-up	The activities that we have detailed above associated with this step change are similar to those that Jemena presented to the AER for its "New Tariff" step change that the AER approved in its Preliminary Decision for them. Although we have approximately 665,000 customers, compared to Jemena's approximately 320,000 customers, we expect to incur costs associated with new pricing obligations that are comparable to those that the AER has approved for Jemena. We also expect to incur these costs in a similar annual profile to those that the AER approved for Jemena. On this basis, we propose the AER use Jemena's approved step change as a benchmark efficient cost and that it apply this benchmark to us for the 2016 to 2020 regulatory period.

Name	13. National Energy Customer Framework (NECF)					
Amount ($M, Real 2015)	2016	2017	2018	2019	2020	Total
– Regulatory Proposal	-	-	-	-	-	-
– AER Preliminary Decision	-	-	-	-	-	-
– RRP	0.2	0.1	0.1	0.1	0.1	0.7
Legislative / regulatory requirement	In late 2015, the Victorian Energy Minister advised us that the NECF connections arrangements would apply sometime in the 2016 to 2020 regulatory period. The Minister introduced a Bill into the Victorian Parliament on 8 December 2015 – the *National Electricity (Victoria) Further Amendment Bill 2015*. The Victorian Government expects that the Bill will be given assent by the end of March 2016. The Bill allows different parts of the Bill to be proclaimed at different times or, if a section has not been proclaimed, to commence on 1 January 2017. The Bill provides for the: • Implementation of the NER Chapter 5A and Chapter 6 Part DA on connection arrangements and connection policy to commence at a date to be proclaimed in 2016 but no later than 1 January 2017; • Publication of a connection policy (though not AER approved), which is consistent with the connection charge principles, connection charge guidelines, the AER's 2016 to 2020 Distribution Determinations and the legislation of Victoria regulating energy or instruments made for the purposes of the legislation. Whilst the AER does not need to approve the connection policy as part of its Distribution Determination, it can still require compliance with the regulatory framework; • Publication of at least two basic model standing offers for basic connection services for retail customers who are not embedded generators and basic connection services for customers who are micro embedded generators by the commencement date; • The two basic model standing offers to be approved by the AER by a date to be specified by the Minister; and • New energy regulations to be made by the Governor-in-Council with respect to a range of matters, which can include undergrounding, tendering policy (content, public availability etc.) and can include the tendering works for augmentation for connecting generating units or undergrounding. The Explanatory Memorandum accompanying the Bill confirms that the Government's intent is to confirm that the AER may take into account the application of the new connections framework in Victoria when making its Distribution Determinations for the 2016 to 2020 regulatory period. The legislation is public and will be implemented in 2016 or by the latest 1 January 2017. We need to comply with the new connections framework and the consequential changes to the Victorian regulatory instruments and ensure that systems, processes and websites etc. are all updated to meet these requirements.					
Services / capability requirements	The AEMC has issued a final rule on 13 November 2015 to help generators under 5MW connect to distribution networks – National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014, No. 8. The Final Determination provides a decision tree for non-registered generators in relation to the optionality of the regulatory framework for connections[120]. These connections are progressed under less prescriptive processes currently in Victoria under the guidelines. The connection process is outlined in Figure C1[121]. This indicates the performance timeframes on DNSPs to respond to connection applicants and provides the information requirements on responses. This final rule does not yet apply in Victoria given that it has not yet implemented NECF. We will need to ensure that all of the aspects of our connection process comply with the new arrangements, specifically the non-registered embedded generators or more complex micro generator connections. Whilst we have previously prepared for a possible implementation of NECF in early 2012, we will need to review and update a number business processes, including to:					

[120] AEMC Rule Determination, National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014, 13 November 2014, p20,

[121] AEMC Rule Determination, National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014, 13 November 2014, p80

<table>
<tr><th>Name</th><th>13. National Energy Customer Framework (NECF)</th></tr>
<tr><td></td><td>

Update the basic connection services model standing offers for retail customers who are not embedded generators and basic connection services model standing offers for customers who are micro embedded generators by the commencement date and ensure they comply with the current version of Chapter 5A[122];
Publish these model standing offers and update our website[123];
Submit the two model standing offers to the AER for approval by the specified date[124];
Review and update all negotiated connection offer templates that we use to assess compliance against the new framework and implement changes across the business;
Ensure that the further changes in the connections service framework are catered for in the AER approved model standing offers and the negotiated offers and deal with the separation of connection, metering installation and initial energisation processes and the complexities this creates for scheduling[125];
Ensure that the website meets all information requirements – including the enquiry form for connection of embedded generator units (EG), the register of completed EG projects[126] and the information pack requirements[127];
Collate the initial register of completed EG projects over the last year, assess gaps and confidentiality, seek customer consent to release of data, amend the annual Distribution Annual Planning Report (DAPR) processes[128];
Develop tracking processes and reporting capability;
Participate in the consultation on the changes to Victorian instruments – repeal of ESC guidelines, introduction of new electricity regulations by the Victorian Government, amendment to the distribution licence by the ESC, amongst other things;
Review and ensure that our connection policy and tendering policies are in line with the new framework and reassess customer contributions and pioneer scheme management to ensure compliance[129]; and
Update our compliance register and responsibilities following the complete set of regulatory changes and manage implementation.

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<tr><td>Activities / processes impacted to deliver service</td><td>
We must comply with the new connections framework. We will need to undertake a number of additional or expanded activities to manage changes to connection processes and manage the extra level of prescription introduced, manage customer information, manage the new schemes and charging arrangements and the complexity arising from the changes stemming from commencement and then also the later change to the nature of the connection service.
The activities outlined above broadly fall into the following categories:

Model standing offer and negotiated offer review and update to ensure compliance, including legal review and AER approval for the model standing offers;
Amendments to connection processes and customer management to ensure compliance with the new arrangements, updating of work instructions and training;
Publication of the offers, enquiry forms, completed generation projects, information packs, amongst other things;
Performance tracking management; and

</td></tr>
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[122] NER 5A.B.1

[123] NER 5A.D.1

[124] NER 5A.B.2

[125] AEMC National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12 5A.A1

[126] NER 5A.D.1A

[127] Rule 5A.D.1

[128] NER 5A.D.1A

[129] Clause 6.7A.1 of the NER

Name	13. National Energy Customer Framework (NECF)
	• Updating compliance registers for the implementation of the NER and the jurisdictional amendments.
Cost build-up	The implementation will be undertaken by a mix of resources across the business from regulatory, commercial and legal, connections, stakeholder management and complex connections engineers. We have based our cost build-up on the following breakdown of time commitments: Establishment: • Review and updating of model standing offers – basic offer for load and for micro EG at 200 hours and $94/hour; • Review and updating of negotiated offers – mixture of LV and HV connection offers with levels of augmentation, both connection offer and connection with ongoing supply and non-micro EG offers (30kw to 5MW EG) with and without augmentation, 5 offers at 250 hours and $94/hour; • Legal review of all connection offers – 2 basic and 4-5 negotiated offers, $60,000; • Updating of connection processes and documentation – 160 hours at 39$/hour; • Review all updated material and publish – 20 hours at $39/hour; • Updated compliance register and manage communication, implementation – 200 hours at $94/hour; and • Program management and governance – program manager for 6 months at 40% time at $180/hour. Ongoing costs: • Performance tracking and reporting capability development and ongoing – 20% FTE; and • Ongoing connection management to deal with enquiries and increased level of rigour/prescription in all non-basic connections, particularly non micro EG connections under Chapter 5A compared to guideline 15, 0.8 FTE. We consider that an additional connection FTE is required to ensure review and coordination of activities and manage compliance against the more prescriptive process. This cost is estimated at $130,000 per annum. The legal review of all standing offers for compliance with the new connection arrangements will be undertaken externally at a cost of $60,000. We consider that we should undertake one legal review to cover the 2016 implementation and the 2017 changes, although this will depend on the implementation timing in 2016.
Addressing AER reasons for rejection in Preliminary Decision	The new legislation substantially changes our obligations in relation to connections. Doing nothing is not an option. We need to integrate the new requirements into business as usual activities and monitor performance against the new more rigours connections processes. We consider that this is prudent and efficient resourcing to meet the new regulatory obligations to establish the capability and manage compliance with the new requirements. There is a substantial difference in the level of prescription and rigour under Chapter 5A compared to the current Victorian processes. These costs are not included in the base year. Our approach reflects the costs a prudent operator would incur to comply with these new obligations.