06.01.01

Forecast Expenditure Summary – Operating Costs

Contents

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The purpose of this document is to provide a detailed description of Ergon Energy's operating expenditure forecasting process, including our application of the base step trend (BST) methodology. This document also demonstrates how Ergon Energy's operating expenditure forecasts meet the operating expenditure objectives, criteria and factors under the National Electricity Rules (NER), and is comprised of three sections plus relevant attachments:

1. Approach to operating expenditure forecasting
2. Operating expenditure forecasting methodology and application
3. Meeting the operating expenditure objectives, criteria and factors.

1 Introduction

Ergon Energy operates the electricity distribution system in regional Queensland which supplies electricity to over 700,000 customers across a service area of more than one million square kilometres. Ergon Energy incurs operating expenditure to provide a safe, secure, reliable electricity supply to our customers and communities. This expenditure is incurred to fulfil our obligations from a statutory, licence, standards, customer and community and risk management perspective.

Ergon Energy's approach to forecasting operating expenditure for the regulatory control period 2015-20 is outlined in this document. The document supports Ergon Energy's revised Regulatory Proposal by providing further detail on our methodology for forecasting operating expenditure.

1.1 Operating expenditure forecast summary

Ergon Energy proposes the following operating expenditure forecast for the regulatory control period 2015-20:

SCS operating expenditure forecast ($m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
RIN reported operating expenditure ($13-14)	**472.32**						
Less FiT ($13-14)	(120.08)						
Subtotal	*352.24*						
Less overheads	(114.92)						
Base year direct costs ($13-14)	**237.32**	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**
Accounting adjustments	5.08						
CAM adjustments	4.35						
Adjusted base year operating expenditure ($13-14)	**246.75**	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**
Classification changes			(30.31)				
Adjustment for future efficiencies			(1.88)	(1.80)	(1.81)	(1.81)	(1.82)
Output growth		3.98	3.48	2.77	2.44	2.34	2.93
Step changes and bottom-up							
Parametric insurance			13.00				

SCS operating expenditure forecast ($m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Market Transaction Centre			5.20				
Operating expenditure before escalation ($2013-14)	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**	**243.46**
2012-13 de-escalation amount	(7.19)	(7.30)	(7.00)	(7.02)	(7.04)	(7.05)	(7.08)
Real price growth direct operating expenditure			17.72	19.75	21.77	23.82	25.97
Overheads ($2014-15)			83.07	92.68	101.63	106.78	111.96
Total SCS operating expenditure forecast ($2014-15)		**243.43**	**334.01**	**346.59**	**358.18**	**365.89**	**374.31**
Debt raising costs			11.89	12.30	12.62	12.88	13.09
Total SCS operating expenditure forecast, incl. debt raising costs ($14-15)		**243.43**	**345.90**	**358.89**	**370.80**	**378.77**	**387.40**

Ergon Energy's approach to forecasting operating expenditure has been developed with regard to the requirements of relevant sections of the NER in respect of operating expenditure.

In accordance with clause 6.5.6 (c) of the NER, the Australian Energy Regulator (AER) is required to accept Ergon Energy's operating expenditure forecast for the regulatory control period if it is satisfied that the forecast reasonably reflects each of the following (the operating expenditure criteria):

1. the efficient costs of achieving the operating expenditure objectives
2. the costs that a prudent operator would require to achieve the operating expenditure objectives
3. a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Our assumptions, inputs methodology and supporting evidence are focused on satisfying the AER that our forecasts reasonably reflect the requirements of the NER.

In addition to the NER requirements, Ergon Energy's operating expenditure forecast has been developed with specific consideration of the AER's intended approach to assessing operating expenditure, which is outlined in the AER's Expenditure Forecast Assessment Guideline (the Guideline) and accompanying Explanatory Statement.

The AER has indicated a preference for the use of the BST methodology in its Guideline and Ergon Energy's approach incorporates a BST forecast for most operating expenditure categories with a bottom-up methodology used for those cost categories where an alternative methodology was considered more appropriate.

1.2 Our approach

Ergon Energy has traditionally prepared our operating expenditure forecasts through a bottom-up forecast of direct maintenance, operations and customer service costs, with overhead applied in a manner consistent with the Cost Allocation Method (CAM). This approach has generally been accepted by regulators in the past.

In July 2013, the AER queried the value of Ergon Energy's forecasting on a bottom-up basis as its intention (as reflected in the Guideline) was to apply a top-down approach. Further, that even if Ergon Energy was to prepare our forecasts using a bottom-up methodology, the AER would request information on a BST basis to allow it to assess the expenditure forecast by applying its preferred methodology.

This position was consistent with the AER's Explanatory Statement for its draft Guideline: [1]

> *In particular, NSPs may find it useful to devote more effort to justifying their proposed opex allowances through the base-step-trend approach, where the AER has a strong preference to rely on revealed costs, if they have not used it in the past.*

Therefore, while the AER's Guideline was still being finalised, Ergon Energy initiated the implementation of a new methodology for the development of our operating expenditure forecasts. Our Expenditure Forecast Methodology noted this: [2]

> *Given the substantial change that this represents from its historic practice, Ergon Energy is still designing the approach which will allow forecasts to be presented in a manner consistent with the AER's anticipated expectations under the base-step-trend approach.*

Ergon Energy's adoption of the BST methodology for forecasting the majority of its recurrent operating expenditure represents a substantial change in approach from that applied in developing its forecasts for the regulatory control period 2010-15. We have attempted to reconcile our approach with the AER's Guideline, but have found that some departures have been necessary.

Any operating expenditure forecast must demonstrate that it relates to expenditure "properly allocated to *standard control services"* in accordance with the principles and policies set out in the CAM.[3]

Because of the operation of the AER-approved CAM, the forecast for Standard Control Service operating expenditure cannot be developed in isolation. Rather, Ergon Energy's operating expenditure forecast must be developed through:

- the application of a BST methodology to direct operating Standard Control Service costs
- the allocation of forecast overhead costs for direct operating Standard Control Service costs on a basis consistent with the CAM (noting that relevant overhead costs have been subject to BST).

Consistent with the AER's Guideline, Ergon Energy has also excluded some costs from the BST methodology. We outline these costs, and the reasons why we have not applied a BST methodology in this document.

1.3 Operating expenditure forecasting governance

An iterative process of scrutiny and refinement has been applied in the development and application of the BST and bottom-up approaches to forecasting operating expenditure for the regulatory control period 2015-20. An internal management committee, comprised of relevant

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[1] AER (2013), *Better Regulation – Explanatory statement, Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p3.
[2] Ergon Energy (2013), *Expenditure Forecast Methodology 2015 to 2020,* November 2013, p 21.
[3] NER, clause 6.5.7(b)(2)

Executive General Managers and Group Managers, was established with responsibility for overseeing the operating expenditure forecasting process, including scrutiny of methodology, inputs and outputs.

The total forecast operating expenditure for the regulatory control period 2015-20 is endorsed by the Chief Financial Officer and Chief Executive prior to approval by the Ergon Energy Board.

2 Operating expenditure forecasting methodology and application

Ergon Energy's approach to forecasting operating expenditure remains consistent with what we proposed in October 2014. We have simplified modelling arrangements – using a spreadsheet rather than an Access database. In this document we have also attempted to simplify our explanation of the steps taken to forecast our operating expenditure requirement without substantially amending our methodology.

Ergon Energy has developed our forecasts taking into account the AER's Guideline and the requirements of the NER, as well as in-depth analysis of the key factors driving operating expenditure into the future.

The process of forecast development has been informed by independent econometric and benchmarking analysis, and the outcome of this analysis has either been directly applied or included in the consideration of efficiency adjustments.

In order to assist the AER with its assessment of our forecasts, Ergon Energy has selected the most appropriate combination of BST and bottom-up forecasting and other costs applicable to the different categories of expenditure across our operations. We have also provided supporting evidence to satisfy the AER as to the reasonableness of the forecasts proposed.

Customer concerns that have been expressed in response to recent increases in prices have influenced our forecast. We have already delivered price relief in 2015-16 through a substantial intervention in underlying costs in this period. Our forecasts commit the business to finding ways to reduce costs further, while bringing forward the benefit of those reduced costs for customers. This represents a greater sharing of the incentive to reduce costs during the period with customers. We outline how we propose to do this later in this chapter.

The following section outlines the operating expenditure forecasting methodology adopted and its application to developing Ergon Energy's forecast operating expenditure program.

2.1 Base Step Trend methodology

In simple terms, the BST methodology applied by Ergon Energy in preparing its operating expenditure forecasts involves:

- Step 1: Selecting a base year and identifying the reported Standard Control Services operating expenditure (inclusive of the overhead allocation to these costs) for that base year

- Step 2: Identifying separately the components of the reported Standard Control Services operating expenditure in the base year:
  - the Standard Control Services direct operating expenditure costs inherent within the reported base year
  - the indirect costs allocated to the Standard Control Services direct operating expenditure costs which have been applied in accordance with the AER's CAM approved for Ergon Energy
- Step 3: Preparing both the direct operating expenditure and indirect (overhead) costs for BST forecasting. This involves:
  - identifying the Functional Areas implicit within the cost forecasts
  - aggregating overhead costs attributable to Standard Control Services with any other overhead cost that have been allocated to Ergon Energy's regulated activities (Standard Control Services capital expenditure, public lighting capital and operating expenditure, metering capital and operating expenditure and other Alternative Control Services capital and operating expenditure)
- Step 4: For both direct operating expenditure and overhead costs, making necessary adjustments to base year costs so they can be used for forecasting. This includes:
  - adjustments for movements in provisions
  - one-off adjustments to the base year
  - other adjustments due to service reclassification
- Step 5: For both direct and overhead costs, identifying and applying any step changes or any non-recurrent operating expenditure
- Step 6: For both direct and overhead costs, applying a rate of change to reflect changes in expenditure consistent with workload drivers
- Step 7: Applying relevant price escalation to both the direct and overhead component of each Functional Area cost
- Step 8: Allocating overhead costs back to each of the Functional Area direct costs in accordance with the CAM.

The BST methodology applied by Ergon Energy is depicted in the Figure 1 below.

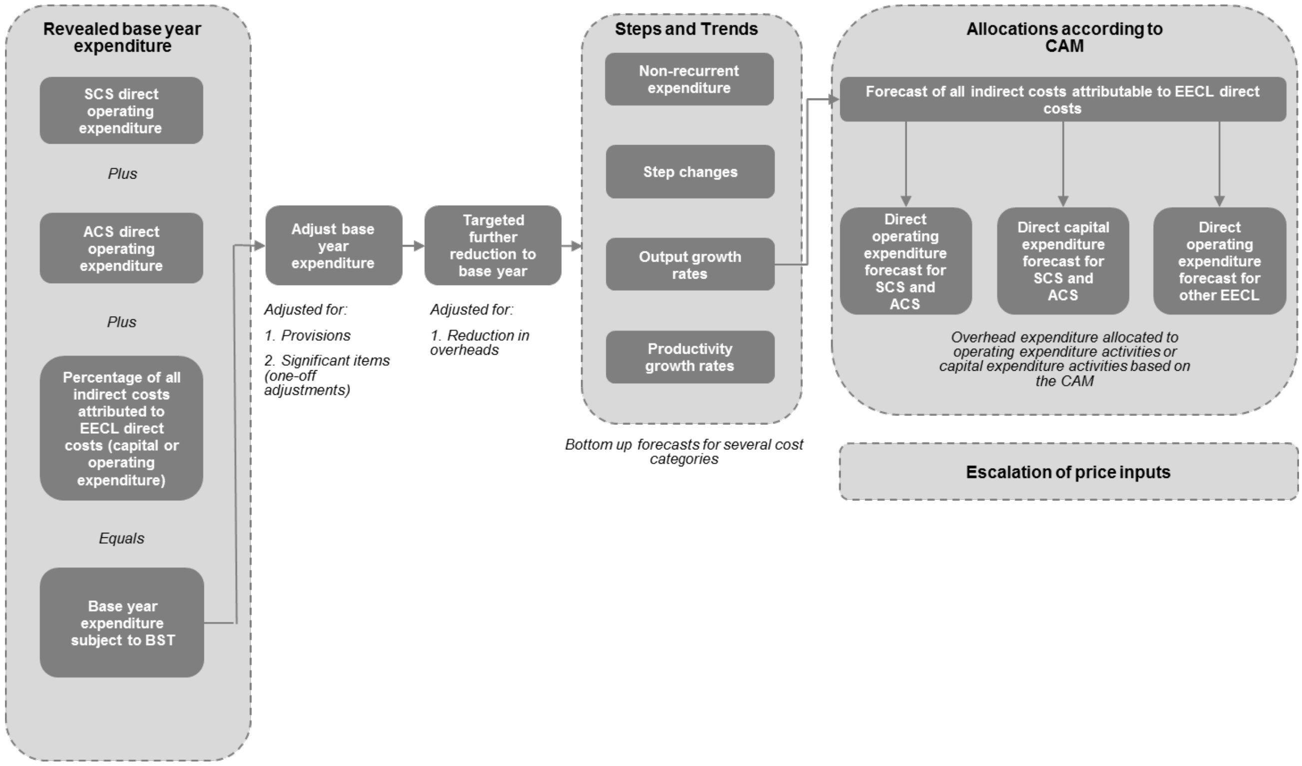

Figure 1: BST approach applied by Ergon Energy

2.2 Base year and approach to adjustments (Steps 1 and 2)

The initial step in developing operating expenditure forecasts under the BST method involves selecting a base year to be used as the basis upon which to build the forecast.

Ergon Energy has chosen the 2013-14 financial accounts as the base year for the purposes of forecasting operating expenditure for the revised Regulatory Proposal. 2013-14 was the fourth year of Ergon Energy's regulatory control period 2010-15 and represents the most recent financial year for which audited regulatory accounts were available at the time the operating expenditure forecasts were prepared.

There is a wealth of literature suggesting that a forecast is best represented based on all available information. As such, the 2013-14 accounts represent the most appropriate starting base year and reflects the most recent 'revealed cost' for Ergon Energy. The reported operating expenditure outlined in the table below is split between the direct portion and the allocated overhead portion:

Table 1: Reported operating expenditure, 2013-14

SCS operating expenditure forecast ($m)	2013-14
RIN reported operating expenditure ($13-14)	**472.32**
Less FiT ($13-14)	(120.08)
Subtotal	*352.24*
Less overheads	(114.92)
Base year direct costs ($13-14)	**237.32**

2.3 Identifying the components of base year costs (Step 3)

2.3.1 Functional Areas for forecasting purposes

Ergon Energy has mapped our revealed costs from our audited 2013-14 year financial data to groupings called 'Functional Areas' for the purposes of our base year data. These Functional Areas are further mapped and combined into category level data for aggregate level reporting. A description of the Functional Areas is provided in Appendix A: List of Functional Areas.

Some of the Functional Areas are, by nature, overhead activities (such as the Finance function). Where a Functional Area is an overhead cost, the overheads are aggregated and spread across all of Ergon Energy's expenditure including both operating expenditure and capital expenditure and across all classifications including Standard Control Services, Alternative Control Services, unregulated and unclassified services.

For BST forecasting purposes, Ergon Energy identified the following Functional Areas that need to be mapped:

- direct Standard Control Services operating expenditure and Alternative Control Services operating expenditure
- overhead activities that are fully or partially attributed to direct Standard Control Services or Alternative Control Services activities.

2.3.2 Differentiation of direct and indirect costs

The reported 2013-14 operating expenditure for Standard Control Services includes both a direct operating expenditure portion and an allocation for overhead. The overhead allocation is determined in accordance with the CAM under a four-step process, outlined below:

1. *Allocation of shared (support) costs between the regulated Distribution Services provided by EECL DNSP and each of the unregulated services provided by the Ergon Energy Group.*

2. *For the costs allocated to the regulated Distribution Services provided by EECL DNSP in Step 1, further allocate the costs between regulated operating expenditure and regulated capital expenditure.*
3. *Calculate the Shared Cost Percentage Rate for each of regulated operating expenditure and regulated capital expenditure.*
4. *Apply the Shared Cost Percentage Rates to the direct operating expenditure and direct capital expenditure in the ERP.*

Because the AER has approved allocations in this manner, the reported Standard Control Services operating expenditure base year costs cannot be trended in a linear manner. This is because the overhead portion applied to Standard Control Services operating expenditure will vary based on the steps outlined above, even if the overhead costs (as an aggregate item) trend in a linear manner.

Because of this Ergon Energy needs to:

1. separate our base year cost into both direct and indirect portions
2. aggregate the indirect portion with other Ergon Energy overhead costs attributable to all activities
3. rend the direct and indirect portions separately
4. reallocate the indirect portion back to direct costs in accordance with the allocation process outlined above.

The overhead portion of operating expenditure in 2013-14 can be aggregated into other overhead applied to Ergon Energy's activities as outlined in Table 2 below.

Table 2: Overhead in 2013-14 base year

Overhead forecast	2013-14
RIN reported operating expenditure less FiT	**352.24**
Base year direct costs	237.32
SCS operating expenditure overhead	114.92
Overhead applied to other non-SCS operating expenditure activities	288.46
Base year overhead costs	**403.38**

2.4 Adjustments to the reported base year costs (Step 4)

Adjustments to the 2013-14 audited operating expenditure numbers have been made to remove expenditure that does not support a recurrent cost for the purposes of forecasting. The adjustment may relate to specific one-off or unusual events (i.e. costs that are not representative of a typical year of recurrent operating expenditure). Consistent with the AER's Guideline, Ergon Energy has also made adjustments to the base year expenditure to account for any movements in provisions. The removal of these items creates an efficient starting point or 'efficient base year' from which to commence the operating expenditure forecast.

2.4.1 Necessary adjustments to 2013-14 direct costs

Movements in provisions are removed from the base year to represent the cash movement during the base year, consistent with the AER's approach to provisions as outlined in the Guideline.

Our forecasts include an adjustment in 2015-16 reflecting the changes in service classification, primarily relating to the AER's decision to reclassify Type 5 and 6 metering services as Alternative Control Services. This amount totals $30.31 million.

Table 3: Adjustments to base year direct costs

SCS operating expenditure base year and adjustments (direct $13-14m)	2013-14	2014-15	2015-16
Base year direct costs	**237.32**		
Re-allocation of DMIA to revenue	(0.88)		
Identified coding errors	2.30		
Movement in provisions	1.91		
Adjustment for liability claims	1.88		
CAM adjustments	4.23		
Classification changes			(30.31)
Adjusted base year direct costs	**246.75**	**246.75**	**216.44**

2.4.2 Necessary adjustments to 2013-14 overhead costs

Adjustments are also required to overhead activity which is shown in Table 4 below.

Table 4: Necessary adjustments to overhead costs

Ergon Energy overhead base year and adjustments (direct $13-14m)	2013-14	2014-15	2015-16
Base year overhead costs	**403.38**		
Movement in provisions	3.20		
Other accounting adjustments	(3.91)		
CAM adjustments	(4.35)		
Classification changes			0.00
Adjusted base year overhead costs	**398.33**	**398.33**	**398.33**

2.4.3 Other adjustments

Ergon Energy's October proposal noted a number of initiatives aimed at reducing expenditure during the period following a detailed risk assessment of maintenance programs. As a result, inspection and minor maintenance cycles for a range of assets including poles, pillars, pad-mount substations and pole-mounted switchgear were extended based on these reviews. Additionally, the introduction of a maintenance framework for substation equipment implemented jointly across Ergon Energy and Energex resulted in reductions in 2012-13 and 2013-14 substation maintenance expenditure.

Reported maintenance opex in 2013-14 is lower than trend in some categories. Air break switch maintenance and pole top inspection programs were temporarily reduced in 2012-13 and 2013-14 as resources were moved to address a significant safety issue with air-break switches[4]. The out-turn expenditure for these programs is not necessarily representative of recurrent costs for these functional areas.

On this basis, opex would have been higher in 2013-14 assuming a "normal" year and, under normal bottom-up expenditure forecasting arrangements, we would reconcile back to normalised amounts between functional areas. This would have most likely also increased expenditure in some areas and decreased it in others.

We note however, the AER's reluctance to address this within the total opex forecasting arrangements. Ergon Energy notes the following in the Preliminary Determination for Energex:

> *Energex uses its opex model to forecast expenditure for each opex category or 'functional area'. It stated that within its model it had reallocated some expenditure from one opex category to a different category for the forecast period. These adjustments had no net impact on total opex. We, however, forecast total opex, rather than opex at the category level. Consequently we did not make the same adjustments[5].*

The AER made similar comments in relation to Ergon Energy's within period expenditure adjustments to functional areas:

> *For instance, while total opex is relatively recurrent, categories of opex, or opex on projects and programs are not recurrent. That means each year a service provider could spend more opex on some areas (such as remediation of contaminated land) and less opex on other areas. A prudent and efficient service provider could achieve compliance with existing regulations by redirecting funds from categories of opex which were expected to decline in the forecast regulatory control period. Alternatively it could do this by reprioritising its opex budget. We do not agree that a prudent and efficient service provider would need to seek additional funding from consumers above our estimate of base opex[6].*

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[4] A significant safety issue occurred with ASEA Brown Boveri (ABB) air-break switches. This issue was also occurring in all distribution companies across Australia. This resulted in the need to replace 2,000 air-break switches across the overhead network. This program cost in excess of $30 million and at the time severely constrained the availability of overhead live line resources Australia wide. Ergon Energy saw the opportunity to focus this constrained resource on the immediate need and deferred all air-break switch maintenance on the remaining 3,500 switches in service, and temporarily curtailed the pole top inspection – wet areas programs. Both of these programs ceased for the remainder of 2012-13, the entire 2013-14 year and are restarted in 2014-15 with the completion of the air-break switch replacement program.

[5] AER Preliminary Decision Energex – 2015-20 Attachment 7 Opex page 7-268

[6] AER Preliminary Decision – Ergon Energy Attachment 7 Opex page 7-307

On this basis we have not made adjustments to the base year revealed costs to reflect changes between functional areas, nor have we sought to adjust the total base year opex to normalise for under-expenditure in some opex functional areas.

2.5 Step changes and bottom-up adjustments (Step 5)

Ergon Energy's BST forecast methodology applies step changes and a rate of change (steps and trends) to determine forecast operating requirements.

Ergon Energy has had regard to the AER's requirements for determining step changes and has considered which step changes should be added (or subtracted) for any 'other costs' not captured in the base year operating expenditure.

2.5.1 Step changes and other bottom-up adjustments

Table 5 summarises the step changes that Ergon Energy has proposed over the regulatory control period 2015-20, with each step change described further below. Further detail can be found in our supporting document, *06.01.04 – (Revised) Step Changes for Operating Costs*.

Table 5: Step changes

Step change	Driver and description	Step 2015-16 ($m)
Market Transaction Centre	Anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the Minimalist Transitioning Approach reaches an end.	$5.2
Parametric Insurance	The base year expenditure does not include expenditure relating to efficient and prudent level of insurance cover to mitigate the financial risks Ergon Energy faces in relation to damage caused to its electricity network by large scale storm and cyclone events. This is because historically, there has been a lack of available and efficiently priced insurance cover in the insurance markets.	$13.0
ICT Asset Service Fee (to overhead costs)	Asset Service Fee expenditure required in the regulatory control period 2015-20 for ICT capital works that were approved in the regulatory control period 2010-15 but were delivered after the 2013-14 year.	Step changes in each year of the period, totalling $23.53
ICT operating fee (to overhead costs)	Ergon Energy has included increased operating expenditure for a range of systems required to operate in a fully contestable market (vertically integrated systems to independent systems operating via market interfaces).	$5.0

2.6 Trending base year expenditure for output growth (Step 6)

2.6.1 Output growth rates methodology

The AER recognises that distribution networks grow in size, and therefore face a corresponding increase in the cost associated with operating and maintaining the network. The annual growth rate of the network is determined with reference to network growth drivers that are considered to approximate the resultant growth in operating expenditure.

Consistent with the AER's accepted approach to calculating growth, Ergon Energy has calculated two growth drivers: customer growth and network growth.

Customer growth is calculated as the annual forecast growth in customer numbers over the regulatory control period 2015-20. The customer number forecast is based on an Ergon Energy econometric model described below.

Network growth has been calculated as a simple average of the forecast annual growth in zone substation capacity, distribution line length and the number of distribution transformers over the forthcoming regulatory control period. The methodology for calculating the composite driver, including the methodology for each factor, is discussed below.

Customer growth

In 2009, the AER engaged McLennan Magasanik Associates (MMA) to review Ergon Energy's demand forecasts as part of the regulatory determination process. MMA made a number of recommendations, including recommendations regarding the forecast for energy consumption together with customer number forecasts.

Ergon Energy addressed these recommendations by developing a range of demand forecast models in consultation with external parties, including development of a model to forecast customer numbers.

The model and forecast produce energy consumption and customer numbers projections over a forecast horizon of up to 10 years, with a capability of producing both quarterly and annual forecasts.

The model is econometrically driven and captures the relationship between energy and its fundamental drivers. It therefore differs from previous approaches adopted by Ergon Energy that primarily involved the extrapolation of historical trends.

The econometric approach provides details on the flexibility to incorporate new and dynamically changing information. It also provides the basis for a well-specified and transparent modelling tool that is targeted to satisfy regulatory requirements for a best practice approach to forecasting energy demand and customer numbers. Ergon Energy uses the annual change in forecast customer numbers from the economic model for the Customer Growth driver.

Network growth

Network growth is calculated as the simple average of the annual growth in zone substation capacity, line length and the number of distribution transformers over the forthcoming regulatory control period. It is noted that the AER adopted this approach in its last determination for the Victorian Distribution Network Service Providers (DNSPs) and Aurora Energy. Ergon Energy's forecast is based on historic data derived from Regulatory Information Notice (RIN) data and internal strategic data sets. The distribution line length and the zone substation capacity forecasts are reported in the reset RIN.

Distribution line length

The method to forecast the kilometres of conductor for the RIN is used to calculate the percentage year on year change for distribution line length. The methodology is as follows:

- Match the purchased conductor in the requestion orders against historical capital expenditure to find the amount of conductor installed and augmentation expenditure for each year
- Calculate the ratio of conductor installed to capital expenditure over the 2008-2014 calendar year period
- Multiply this ratio by forecast capital expenditure each year to forecast the total conductor installed each financial year
- Divide the total new conductor according to the current (2014) percentage distribution of conductor across the Overhead and Underground voltage categories
- Accumulate the year on year new conductor to find total circuit lengths for each year in the forecast.

The following assumptions have been made:

- The percentage distribution of conductor across the Overhead and Underground voltage categories will remain constant in the future. Historically, it has been very stable, so Ergon Energy believes this assumption to be reasonable.
- Capital expenditure on lines augmentation projects scales in a linear basis with new conductor added, when taken at a network-wide level.

Zone substation capacity

The method to forecast the zone substation capacity for the reset RIN is used to calculate the percentage year on year change. The methodology involves using a linear trend performed over historical years and projected across the forecast years.

Assumptions that have been made are:

- Historical years with significant data corrections have been excluded from linear trend calculation
- Where historical years have been excluded from the trend calculation, the trend has been applied to latest historical value and projected across the forecast years.

Number of distribution transformers

The count of distribution transformers is from Ergon Energy records and is not directly reported in the reset RIN. Ergon Energy's method to calculate the forecast is to:

- Average historic distribution transformer rates of change.
- The average is used to generate a year-on-year forecast of network measures linked to the customer number forecasts from Ergon Energy's econometric forecasts.

This forecasting approach provides a link to the forecast of customer numbers normalised for the attributes of Ergon Energy's network topology.

Table 6 represents the output growth rates applied for each output growth driver, in establishing network growth and customer growth rates.

Table 6: Output growth rates

Output growth driver	2015-16	2016-17	2017-18	2018-19	2019-20
Length of Distribution Lines (forecast)	0.26%	0.28%	0.26%	0.14%	0.14%
Distribution Transformers count (forecast)	2.10%	2.29%	2.10%	2.08%	2.08%
Capacity of Zone substations (forecast)	1.58%	0.61%	0.39%	0.38%	1.21%
Average customer numbers (forecast)	1.64%	1.80%	1.65%	1.64%	1.65%
Network Growth	**1.31%**	**1.06%**	**0.92%**	**0.87%**	**1.14%**
Customer Growth	**1.64%**	**1.80%**	**1.65%**	**1.64%**	**1.65%**

In developing our output growth rates Ergon Energy has had regard to the elements raised in section 4.2.1 of the Guideline and considers that:

- The methods used to forecast network growth and customer growth align with the NER objectives as they provide a realistic method for projecting required demand for services to maintain the quality, reliability and security of supply of Standard Control Services and the distribution network system.
- The growth in output rates reflect the expectations of customers in respect of the services provided to customers.

The rates are of a sufficiently material nature to be included in the BST forecast. Ergon Energy applies a growth driver to each operating expenditure category forecast using the BST methodology.

The application of a growth driver to the operating expenditure category and the rationale for the application is shown in the Table 7 below.

Table 7: Application of growth driver to operating expenditure category

Operating expenditure category	Growth driver	Rationale
Network operating costs	Network growth	A composite network growth factor (network growth based on line length, distribution transformers, and substation capacity) should result in a forecast of operating expenditure that most closely reflects the

Operating expenditure category	Growth driver	Rationale
Network maintenance costs		actual growth in operating and maintenance activity levels, because growth in the level of work effort required to operate and maintain assets is commensurate with growth in the assets themselves.[7]
Other operating and maintenance costs	Customer growth	The use of a customer number growth driver should result in a forecast of operating expenditure that most closely reflects the actual growth in operating activity levels, because as the customer base of a network increases, the cost of operating and administering the network will also increase.[8] Growth in customer numbers is an appropriate growth driver as it reasonably reflects a realistic expectation of the demand forecast and cost inputs required to meet or manage the expected demand. The AER states that growth in customer numbers is a better proxy for overheads and non-direct operating expenditure items.[9]

2.6.2 Leveraging changes we have made in 2010-15 to reduce overhead costs in future years

In seeking to address the long term interests of consumers to achieve further sustainable price reductions, Ergon Energy incorporated a reduction in forecasts equivalent to 10% to our 2013-14 base year operational overhead costs.[10] We have also incorporated an annual reduction of 0.75% to forecast operating expenditure.[11]

This reduction represents a commitment and challenge to Ergon Energy. However, the outcomes are comparable to levels of operating expenditure identified by independent analysis (Independent Review Panel on Network Costs) and benchmarking (Huegin).

2.7 Escalation for cost inputs (Step 7)

2.7.1 Real price growth

Ergon Energy engaged the independent engineering consultant Jacobs/Sinclair Knight Mertz (Jacobs/SKM) to develop real cost escalation factors for the four cost elements identified in the chart of accounts: labour; contractors; materials; and other. Ergon Energy dissects the 2013-14 base year costs into the escalator categories and uses the revealed percentage split as a basis for forecasting any increases for the regulatory control period 2015-20.

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[7] AER (2010), *Final Decision Appendices – Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-2015*, October 2010, p181.

[8] Ergon Energy realises that forecasting customer growth is not a holistic approach to determining our operating expenditure growth. We have used customer numbers for only Functional Areas that relate to overheads and other non-direct operating expenditure activities in line with regulatory precedents. All maintenance expenditure is based on growth in network assets.

[9] AER (2010), *Final Decision Appendices – Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-2015*, October 2010, pp191-192.

[10] Operational overhead costs exclude ICT and fleet related costs.

[11] Excluding ICT asset service fee costs.

- Materials: no real increase has been applied to all materials used in undertaking repairs and maintenance. The price growth increase has been determined based on advice from Jacobs/SKM
- Contractors: a real increase has been applied to contractor rates. The price growth increase has been determined based on advice from Jacobs/SKM
- Labour: a real increase has been applied to productive Ergon Energy labour costs
- Other: no real increase has been applied to the cost of all other direct inputs.

Table 8 provides the real cumulative escalation rate applied by cost element.

Table 8: Real cumulative escalation rate by category

Element	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
General Labour (Labour)	1.000	1.005	1.014	1.024	1.035	1.047	1.058	1.070
Utility Sector Labour (Contractors)	1.000	1.005	1.014	1.024	1.035	1.047	1.058	1.070
Professional Services	1.000	1.016	1.024	1.033	1.043	1.053	1.064	1.074

Our supporting document, *06.02.02 – Jacobs: Cost Escalation Factors 2015-20*,[12] details the findings for real price increases and how they apply to Ergon Energy.

We apply a two-step process to applying price escalation to our direct and overhead costs for forecasting purposes. This involves:

- First, de-escalating all of the costs in the BST model to 2012-13 dollars. This is because our capital expenditure inputs are in 2012-13 dollars so we convert all expenditure to common dollar un-escalated inputs in order to ensure allocation of overhead and price escalation occurs on a common dollar basis.
- Then, all inputs (which are now in 2012-13 dollars) are escalated to 2014-15 dollars in our TRISH model. For operating expenditure escalation, we use the price escalators identified above.

For overhead costs, the outcomes of the two-step process are demonstrated in Table 9 below.

Table 9: Impact of price growth on overheads

Overhead forecast ($m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Overheads before escalation ($2013-14)	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**	**416.36**
2012-13 de-escalation amount	(10.67)	(11.36)	(12.62)	(14.27)	(15.94)	(17.94)	(19.98)
Total overhead forecast ($2012-13)	**355.60**	**354.20**	**365.90**	**375.81**	**382.75**	**390.18**	**396.39**

[12] This is supported by *06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20.*

Real price growth - overheads only		25.96	35.57	45.64	57.28	70.73
Total overhead forecast ($2014-15)	**354.20**	**391.86**	**411.38**	**428.39**	**447.46**	**467.12**

A similar approach is undertaken for the direct Standard Control Services operating expenditure component, as shown in Table 10 below.

Table 10: Impact of price growth on operating expenditure forecast

SCS operating expenditure forecast ($m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Operating expenditure before escalation ($2013-14)	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**	**243.46**
2012-13 de-escalation amount	(7.19)	(7.30)	(7.00)	(7.02)	(7.04)	(7.05)	(7.08)
Real price growth direct operating expenditure			17.72	19.75	21.77	23.82	25.97
Overheads ($2014-15)			83.07	92.68	101.63	106.78	111.96
Total SCS operating expenditure forecast ($2014-15)		**243.43**	**334.01**	**346.59**	**358.18**	**365.89**	**374.31**

2.8 Forecast and allocation of overhead costs (Step 8)

The above steps provide a forecast for both the direct operating expenditure and Ergon Energy regulated overhead portion of the forecast.

Ergon Energy has applied the BST methodology to forecast our total overhead (support) costs for the regulatory control period 2015-20. Ergon Energy allocates costs between categories of distribution services in accordance with the CAM that has been approved by the AER. The overhead forecast, using the similar BST approach is outlined in Table 11.

Table 11: Forecast overheads for all EECL services

Overhead forecast	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
RIN reported operating expenditure less FiT	**352.24**						
Base year direct costs	237.32						
SCS operating expenditure overhead	114.92						
Other overhead applied to regulated activities	288.46						
Base year overhead costs	**403.38**	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**
Accounting adjustments	(0.71)						
CAM adjustments	(4.35)						
Adjusted base year operating expenditure	**398.33**	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**
Classification changes							
Adjustment for future efficiencies	(32.06)	0.00	(2.54)	(2.60)	(2.62)	(2.65)	(2.67)
Output growth		5.42	5.54	6.22	5.78	5.80	5.89

Overhead forecast	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Step changes and bottom-up							
Asset service fee	0.00	(6.12)	4.96	7.95	5.45	6.28	5.02
IT and communications costs			5.00				
Overheads before escalation ($2013-14)	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**	**416.36**

Ergon Energy's CAM sets out how the Ergon Energy Group attributes costs to, or allocates costs between, the regulated distribution services and unregulated services provided by the Ergon Energy Group. Ergon Energy applies our CAM to prepare forecast operating expenditure to be submitted to the AER in accordance with clause 6.5.6 of the NER.

For overhead costs, we allocate the overheads to the Standard Control Services operating expenditure using the CAM process. This allocation is set out in Table 12.

Table 12: Allocation of forecast overheads to services categories

Overhead forecast ($m)	2015-16	2016-17	2017-18	2018-19	2019-20
SCS operating expenditure overheads	83.07	92.68	101.63	106.78	111.96
SCS capital expenditure overheads	223.94	223.40	221.64	228.80	236.11
ACS overheads	68.22	78.31	87.94	94.47	101.29
Non-regulated overheads	16.65	17.00	17.18	17.43	17.76
Total overheads ($2014-15)	**391.88**	**411.39**	**428.39**	**447.48**	**467.12**

The chart below shows that the movement in overheads will vary; both as a function of the previous years' overheads, as well as the proportional allocation to each of the forms of control.

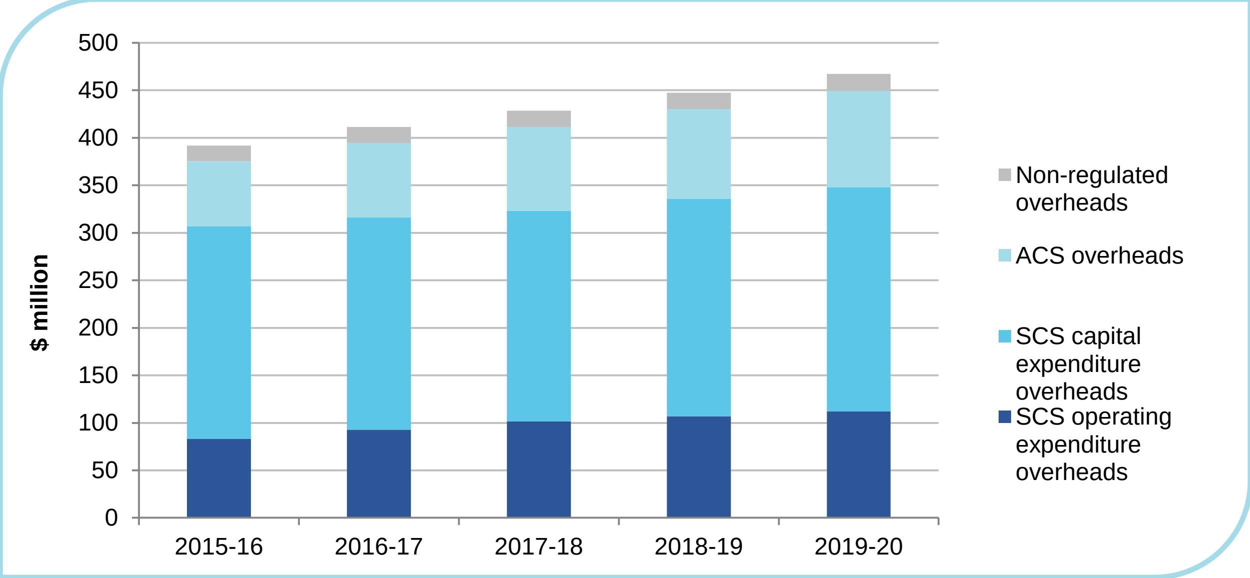

Figure 2: Allocation of forecast overheads to service categories

Refer to section 3.2 of the our supporting submission, *Ergon Energy – Capitalised Overheads and ICT Expenditure – Response*, for an illustration of how we have applied the CAM in allocating overheads to direct operating expenditure and direct capital expenditure.

2.9 Other issues

2.9.1 Debt raising costs

Ergon Energy is proposing a debt raising allowance to compensate for the transactional costs that a prudent service provider acting efficiently incurs whilst raising debt. Ergon Energy engaged Incenta Economic Consulting (Incenta) to undertake an independent review of the benchmark efficient costs for Ergon Energy, recognising the development of regulatory recognition of debt raising costs and its components with specific consideration of the recent PricewaterhouseCoopers (PwC) methodology report written for the Energy Network Association (ENA) and Powerlink.

Based on Ergon Energy's PTRM, Incenta proposes a debt raising operating cost of 19.7 basis points per annum (bppa) on the regulatory debt comprised of:

- 9.9 bppa for debt raising transaction costs relating to the debt component of the Regulatory Asset Base (RAB) of $6.28 billion
- 4.9 bppa to establish and maintain bank facilities required to meet Standard & Poor's (S&Ps) liquidity requirement conditions for maintaining an investment grade credit rating
- 5.0 bppa to compensate for the requirement (as a condition of maintaining an investment grade credit rating) to refinance debt three months ahead of the re-financing date.

Although Incenta agrees with the PwC methodology to calculate the transaction costs, Incenta disagrees with the methodology to calculate the S&Ps liquidity requirement and re-financing costs. In the past, these costs have been described as being "indirect costs" by PwC. However, Incenta has researched this point and concluded that these are direct costs that any regulated business would incur raising debt.

Incenta and S&Ps disagree with PwC's categorisation of liquidity costs and re-financing three months ahead as being indirect. This cost represents cash costs that regulated entities are required to incur in order to meet and maintain the requirements for an investment grade credit rating and are therefore direct costs. Incenta's discussion with S&Ps confirms that they too consider these costs to be direct costs, which are fundamentally no different to other direct costs associated with debt raising that have been recognised as direct costs in the past.

The Incenta report is attached for further information at 06.02.04.

Allowance for debt raising transaction costs relating to the debt component of the RAB

Incenta applies PwC's market research to benchmark a debt-issuing transaction cost allowance for Ergon Energy. PwC found that Australian businesses issuing bonds in the United States (US) are incurring an arrangement fee of 8.51 bppa; this cost is independent of size, term, issuance, and issuance size. The remainder of the transaction fee is based on PwC's interviews with investment bankers, lawyers, and credit rating agencies.

Allowance for costs associated with maintaining bank facilities required to meet S&Ps liquidity requirement

Incenta has employed S&Ps formula for determining the liquidity requirements by deriving a direct cost estimate of the buffer required for a business whose financing arrangements conform to those of the benchmark entity. This 'bottom-up' approach to modelling uses the forward cash flow from the PTRM. That is, Incenta has taken the cash flow forecasts for Ergon Energy, and have solved for the quantum of undrawn committed bank lines that would be required to achieve a cash flow sources / uses ratio of 1.1x in each year of the new regulatory control period, and achieve sources equal to uses if a 15 per cent reduction in EBITDA is modelled, using the cash flow forecasts that are generated by the AER's PTRM for Ergon Energy's Regulatory Proposal.

Applying this approach, Incenta found that over the forecast regulatory control period, the liquidity reserve required to achieve S&Ps ratio to maintain an investment grade credit rating lies between 6.8 per cent and 8.0 per cent of benchmark RAB debt. The corresponding benchmark cost of maintaining the required liquidity reserve is estimated based on the level of benchmark regulatory debt at a levelised cost of 4.9 bppa.

Allowance for costs associated with S&Ps requirement to finance three months ahead

Incenta has employed the completion methodology to estimate the cost of re-financing bonds three months ahead of their maturity. Incenta also notes that an inclusion of re-financing costs does not represent a 'double-counting' of costs that have been provided elsewhere.[13]

Ergon Energy considers the forecast reasonable considering the AER should be using a minimum period of four months to calculate the early issuance costs due to the implementation of the new pricing proposal rule change published in November 2014 effectively brings the pricing proposal process forward by three months.

Under the new rules, network service providers' (NSPs) regulatory resets and debt refinancing will be required to be completed by 28 February each year to allow sufficient time for the cost of debt to be calculated for the next regulatory year and incorporated into the pricing proposals.
Ergon Energy considers these Rule changes will impose a regulatory constraint which will require

[13] The AER previously rejected ETSA Utilities' (now SA Power Network) proposal for a refinancing allowance based on advice that the costs were double counted.

NSPs to refinance debt at least four months ahead of the start of the next regulatory year. NSPs will be required to change their risk management strategies to transact four months ahead (at a minimum) by issuing forward starting swaps or pre-issuing debt, however in practice the early issuance period is likely to be six to nine months.

Although Ergon Energy is likely to face higher costs due to rule changes, Ergon Energy is requesting an allowance in line with Incenta's advice of a three month ahead re-financing cost of 3.1 percent bppa. Ergon Energy believes this allowance will likely be below the actual cost that we will incur over the next control period.

Based on the advice provided, Ergon Energy proposes that a margin of 19.7 basis points per annum should be applied to the notional value of debt as detailed in Table 13.

Table 13: Debt raising costs, real $2014-15

$m	2015-16	2016-17	2017-18	2018-19	2019-20
Debt raising costs	11.89	12.30	12.62	12.88	13.09

The full Incenta report can be found at *06.02.04 – Debt Raising Transaction Costs*.

3 Meeting the operating expenditure objectives, criteria and factors

The AER has indicated it will assess the methodology used by a NSP to derive its expenditure forecasts (including assumptions, inputs and models) in order to determine whether the NSP's methodology is a reasonable basis for developing expenditure forecasts that reasonably reflect the NER objectives and criteria.[14]

In this section, Ergon Energy demonstrates that the methodologies we have developed and applied are consistent with the operating expenditure objectives and criteria and have taken account of the operating expenditure factors, as appropriate.

A more comprehensive description is provided in Ergon Energy’s *06.01.05 – Meeting the Rule Requirements* supporting document.

3.1 Operating expenditure objectives

Ergon Energy has established our operating expenditure forecasts to comply with the operating expenditure objectives specified in the NER. Ergon Energy has demonstrated this by:

- examining our revealed base year costs incurred in meeting current service level and regulatory obligations and any planned efficiency adjustments
- assessing the sufficiency of our current compliance with regulatory obligations to identify step changes for corrective actions
- assessing foreseeable changes in obligations that will affect our operating activities and costs to identify step changes
- incorporating output growth, real price growth and productivity growth from expert determined demand growth and input cost analysis.

Table 14 below demonstrates how Ergon Energy has achieved the operating expenditure objectives.

Table 14: Achieving the operating expenditure objectives

Operating expenditure objective	Clause	Ergon Energy actions to ensure compliance
meet or manage the expected demand for standard control services over that period;	6.5.6(a)(1)	Ergon Energy has prepared our forecast costs to take into account the effects on expenditure of growth in peak demand, customer numbers and consumption forecasts. Ergon Energy’s load and customer forecasting methodologies are based on established forecasting practice and support the growth rates used to develop the forecast trends.

[14] AER, Explanatory Statement Expenditure Forecast Assessment Guideline, p81.

Operating expenditure objective	Clause	Ergon Energy actions to ensure compliance
comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;	6.5.6(a)(2)	Ergon Energy has assessed our current compliance (and associated base costs) as well as assessing corrective actions and additional new obligations (and associated step changes).
To the extent that there is no applicable regulatory obligation or requirement in relation to maintain the quality, reliability and security of supply of standard control services; or the reliability or security of the distribution system through supply of standard control services, to the relevant extent: maintain the quality, reliability and security of supply of standard control services; and maintain the reliability and security of the distribution system through the supply of standard control services; and	6.5.6(a)(3)	Ergon Energy has assessed our requirements to maintain the quality, reliability and security of supply of Standard Control Services as part of our annual network management planning process.
maintain the safety of the distribution system through the supply of standard control services.	6.5.6(a)(4)	Ergon Energy has assessed our requirements to maintain the safety of the distribution system as part of our network management planning process.

3.2 Operating expenditure criteria

Ergon Energy has developed our operating expenditure forecasts to ensure total operating expenditure for the regulatory control period reasonably reflects each of the operating expenditure criteria. Ergon Energy has demonstrated this by:

- implementing a range of internal efficiency initiatives designed to deliver significant efficiencies reflected in the efficient base year
- adopting a BST approach with modest estimates of output and real price growth
- developing forecasts based on realistic expectations of demand, including independent verification of demand forecasts that underpin real price growth (i.e. Jacobs/SKM)
- comparing with peer NSPs for output growth and productivity growth factor calculations.

Table 15 below demonstrates how Ergon Energy has reflected the operating expenditure criteria.

Table 15: Reflecting the operating expenditure objectives

Operating expenditure criteria	Clause	Ergon Energy actions to ensure compliance
The efficient costs of achieving the operating expenditure objectives.	6.5.6(c)(1)	Implemented a series of internal and external efficiency initiatives, as well as benchmarking analysis.
The costs that a prudent operator would require to achieve the operating expenditure objectives.	6.5.6(c)(2)	Ergon Energy's operating expenditure forecasts demonstrate prudency through the application of a rigorous forecasting and planning process and a best practice investment governance framework which requires comprehensive cost benefit analysis to be undertaken to support project investment decisions. This process exists for network and corporate initiatives and requires consideration of alternatives

Operating expenditure criteria	Clause	Ergon Energy actions to ensure compliance
		and options analysis to inform the investment outcomes.
A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.	6.5.6(c)(3)	Ergon Energy's load and customer forecasting methodologies are based on established forecasting practice and support the growth rates used to develop the forecast trends. Ergon Energy's real price cost inputs have been developed having regard to the Jacobs/SKM Report on Electricity Industry Labour, Commodity and Asset Price Costs Indices.

3.3 Operating expenditure factors

Table 16 below demonstrates how Ergon Energy has taken account of the operating expenditure factors in developing our operating expenditure forecast for the regulatory control period 2015-20.

Table 16: Consideration of the operating expenditure factors

Operating expenditure factor	Clause	Ergon Energy actions to demonstrate
(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;	6.5.6(e)(4)	Refer to *0A.01.02 – (Revised) Journey to the Best Possible Price* and *0A.01.01 – How Ergon Energy Compares*.
(5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;	6.5.6(e)(5)	Ergon Energy's BST forecast has been built from a revealed 2013-14 cost base with adjustments made to reflect expectations of operating expenditure efficiency adjustments to the remainder of the regulatory control period 2010-15.
(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;	6.5.6(e)(5A)	Ergon Energy has undertaken a process of customer and stakeholder engagement to determine what customers and stakeholders expect from us. This has been part of an ongoing conversation with our customers and the communities we serve. Further details of the engagement approach are outlined in the "Ergon Energy – An Overview" document.
(6) the relative prices of operating and capital inputs;	6.5.6(e)(6)	Relative prices of operating and capital inputs are considered through the investment governance process in developing options to support cost benefit analysis.
(7) the substitution possibilities between operating and capital expenditure;	6.5.6(e)(7)	Substitution possibilities between operating and capital expenditure are considered at a program planning level as well as at an individual project level through business case options analysis.
(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;	6.5.6(e)(8)	Ergon Energy has considered the application of the AER's incentive schemes in developing our expenditure forecasts.

Operating expenditure factor	Clause	Ergon Energy actions to demonstrate
(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;	6.5.6(e)(9)	N/A
(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);	6.5.6(e)(9A)	Ergon Energy has not proposed any contingent projects. Therefore, no operating expenditure related to contingent projects is included in the forecast.
(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and	6.5.6(e)(10)	Ergon Energy has considered the prudency and efficiency of non-network alternatives in the development of its forecasts. The process for consideration is outlined in the "Demand Management Strategic Plan".
(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);	6.5.6(e)(11)	N/A
(12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.	6.5.6(e)(12)	We note the AER has had regard to additional factors, not identified prior to the lodgement of our October Regulatory Proposal. We have responded to the AER's consideration of these factors in our supporting submission, *Opex (Base Year) – Response*.

4 List of documents referenced

Reference	Title
0A.01.01	How Ergon Energy Compares
0A.01.02	(Revised) Our Journey to the Best Possible Price
06.02.02	Jacobs – Cost Escalation Factors 2015-20
06.02.04	Incenta – Debt raising transaction costs
06.02.07	Jacobs – Addendum Cost Escalation Factors 2015-20
06.01.04	(Revised) Step Changes for Operating Costs
06.01.05	Meeting the Rule Requirements for Expenditure Forecasts
N/A	Ergon Energy – Capitalised Overheads and ICT Expenditure – Response

Appendix A: List of Functional Areas

This attachment provides additional detail to describe the costs assigned to each operating expenditure category.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
Network Operating Costs		52000 Reg Network Operations	This Functional Area relates to the operating costs associated with running the network operations control centres and includes software and hardware support costs for the control centres, labour costs associated with the network operations control centre, and general running costs for the two buildings.
		52010 Embedded Generation	This Functional Area relates to operating costs for generation that is embedded within the network to provide system support in the avoidance of network augmentation. This cost will move to 55100 Non Network Alternatives (Demand Management) in the next period and all costs attributable to this Functional Area will be zero. Costs include fuel and mechanical maintenance of generators.
		52020 Secondary Systems Operations	This Functional Area contains the costs for operating the communications for the network operations centre. It includes costs for managing the Nexium network, operations telecommunication network, costs for coordinating inputs from field devices, and software licences and third party agreements in relation to hardware and software to support communications network operation centre operations. In addition this Functional Area includes costs associated with the scheduled review of HV feeders to ensure protection settings are adequate to meet fault clearance criteria.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
Network Maintenance	Preventative Maintenance Costs	52100 Preventive Reg Comms	This Functional Area includes operating expenses for scheduled maintenance activities which are generated by a scheduled task assigned to equipment and backed up by a strategy or underpinned by the asset management policy. In particular it relates to operating costs associated with the maintenance of the communications assets (e.g. base stations) and includes rents, rates and leases and electricity costs for the equipment, yard maintenance contracts and compliance related maintenance schedule tasks, including fire systems, fall arrest equipment and EPA permits.
		52120 Preventive Reg Lines	This Functional Area includes operating expenses for scheduled maintenance activities which are generated by a scheduled task assigned to equipment and backed up by a strategy or underpinned by the asset management policy. In particular this relates to scheduled maintenance for poles and wires (underground and overhead), distribution transformers (pad and pole-mounted) and pillars. It includes inspections, including pole inspections and line inspections. Drivers include regulatory compliance (pole inspections) and risk assessment of maintenance programs cognisant of cost, risk and reliability.
		52130 Preventive Reg Meters	This Functional Area includes operating expenses for scheduled maintenance activities which are generated by a scheduled task assigned to equipment and backed up by a strategy or underpinned by the asset management policy. In particular this Functional Area relates to scheduled maintenance and inspection for statistical and monitoring metering on Ergon Energy assets.
		52135 Preventive Reg Meters ACS	This Functional Area includes operating expenses for scheduled maintenance activities which are generated by a scheduled task assigned to equipment and backed up by a strategy or underpinned by the asset management policy. In particular this Functional Area relates to scheduled maintenance and inspection for metering associated directly with customer billing - both on NMI metering and under mandatory testing requirements from AEMO. Also included are communication costs on enabled metering. Excluded are meter reading, advice and tariff alteration costs associated with customer installations as this is captured in Customer Service.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		52140 Preventive Reg Protection	This Functional Area includes operating expenses for scheduled maintenance activities which are generated by a scheduled task assigned to equipment and backed up by a strategy or underpinned by the asset management policy. In particular this includes the scheduled testing of protection relays in zone substations to ensure that they operate within appropriate parameters.
		52150 Preventive Reg Subs	This Functional Area includes the operating expenses required for maintaining the asset base within zone substation fences, transformers, fences, earth mat, as well as general maintenance of these structures, rates, leases, electricity costs. It also includes scheduled inspection, measurement and maintenance of equipment including intrusive maintenance, change of oil in circuit breakers in compliance with asset management policies.
		52160 Preventive Reg Veg	This Functional Area includes the total cost of the ROAMES initiative for inspection and survey, as well as the inspection of access tracks underneath and adjacent to power lines, a contribution to the plantsmart (greening Australia) initiative to support the planting of appropriate non-intrusive vegetation around power lines). Vegetation treatment is specifically excluded and captured in 53160 Corrective Reg Veg.
		52170 Preventive Reg Inspection	This Functional Area has not been used for some years – all costs occur under 52120 Lines. Zero costs in forecast.
		52180 Preventive Reg Streetlights	This Functional Area includes operating expenses for scheduled inspection and maintenance activities which are generated by a scheduled task assigned to equipment and backed up by a strategy or underpinned by the asset management policy. In particular this includes public light patrols which cover major roads and the bulk lamp replacements every 3-6 years which cover the minor roads.
		52190 Preventive Reg Alternate Solutions	This Functional Area includes operating expenses for scheduled inspection and maintenance activities in relation to alternate solutions assets. For example, this previously related to the solar photovoltaic assets held on Magnetic Island but as Ergon Energy is transferring these assets, in future this Functional Area will reflect the costs of preventative maintenance for the GUSS (energy storage) units. Future new systems will be integrated as development occurs.
	Corrective Maintenance	53100 Corrective Reg Comms	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure on communications assets including all equipment, buildings, grounds, fences and towers. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		53120 Corrective Reg Lines	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure on poles and wires (underground and overhead), distributions transformers (pad and pole-mounted) and pillars. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts. For Lines this capital expenditure requirement is contained in the established Asset Inspection and Defect Management (AIDM) process.
		53130 Corrective Reg Meters	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure of statistical and monitoring metering on Ergon Energy assets. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.
		53135 Corrective Reg Meters ACS	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure of metering assets associated directly with customer billing. It includes all corrective costs to maintain or rectify metering assets malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.
		53140 Corrective Reg Protection	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure on protection and control assets within zone substations and control centre assets. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.
		53150 Corrective Reg Subs	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure on assets within zone substations including all equipment, buildings, grounds, fences and earth mats. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.
		53160 Corrective Reg Veg	This Functional Area includes the costs to maintain safe clearance bands for vegetation within the vicinity of powerlines with bands dependent upon voltage levels, risk and cost to maintain. This includes trimming and treatment (chemical and removal) activities and accounts for the difference cycles for different areas, general corridor maintenance. It also essentially planned cyclic work with allowance for some reactive works for areas of non-compliance to manage risk.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		53180 Corrective Reg Streetlights	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure on streetlight assets. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.
		53190 Corrective Reg Alternate Solutions	This Functional Area relates to the unplanned or corrective costs of maintaining or rectifying asset malfunction or failure on alternate solution assets. It includes all corrective costs to maintain or rectify asset malfunction or failure classified as operating expenditure with costs classed as capital expenditure as per financial rules contained within capital expenditure forecasts.
	Forced Maintenance	54100 Forced Regulated Maintenance	This Functional Area includes the activities undertaken in direct response to unexpected events to safely restore supply and asset integrity.
		54190 Forced Reg Alternate Solutions	This Functional Area includes the costs of responding to events for alternate systems assets such as GUSS units and solar panels on Magnetic Island.
Other O&M Costs	Meter Reading	56020 Meter Reading - Mass Market	This function pertains to the cyclical reading of customer meters for retail providers and the customer initiated requests for final readings. These services are Standard Control Services, the costs of which are recovered through network charges billed to electricity retailers. Standard Control Services are core network, connection and metering services associated with the access and supply of electricity to customers.
	Customer Service	56000 Customer Installation Services	This function covers the cost of maintenance, repair and replacement of standard meters at customer installations which are considered minimum regulatory requirements. These services are Standard Control Services, the costs of which are recovered through network charges billed to electricity retailers. Standard Control Services are core network, connection and metering services associated with the access and supply of electricity to customers.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		56010 Network Metering	This function covers cost of monitoring, minor repair and settings of relay equipment and time switching equipment. It includes actioning cold water reports and communication and information technology operating costs associated with metering. These services are Standard Control Services, the costs of which are recovered through network charges billed to electricity retailers. Standard Control Services are core network, connection and metering services associated with the access and supply of electricity to customers.
		56050 Revenue Protection Services/Meter Tamper	This function is also a Standard Control Service and entails locating, monitoring and correcting electrical installations where theft or tempering has occurred. It would also include proactive activity such as education and awareness.
		56060 Prescribed Services Other	This activity is now redundant.
		56070 Public/Consumer Safety	This function covers education and customer contact in respect to Electrical Safety issues. These services are Standard Control Services, the costs of which are recovered through network charges billed to electricity retailers. Standard Control Services are core network, connection and metering services associated with the access and supply of electricity to customers.
		56080 Non Proceeding CICW	This function captures the cost of cancelled customer requested capital projects which have incurred costs such as preliminary design, engineering investigation, third party approvals(but not exclusively) after initial customer approval and acceptance of offered commercial terms. Their acceptance has been followed by a request for cancellation of the works and this activity represents the costs incurred between acceptance date to cancellation which is recoverable from the customer. Where works cancellations are not the fault or instigation of the customer (non-chargeable) and no cost recovery occurs, those costs are treated as a support or overhead activity and not captured against this activity.
		56200 Alternate Control Services - General	This activity covers all Alternative Control Services which Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which are in addition to our main network, connection and metering services and are levied as a separate charge to those parties. Typically these services are demand related and are fee based, quoted services, street lighting and default metering services.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		59010 Customer Contact/Advisory Services	This function covers customer contact time by field employees for issues raised other than Safety and not specific to any other type of works. These services are Standard Control Services, the costs of which are recovered through network charges billed to electricity retailers. Standard Control Services are core network, connection and metering services associated with the access and supply of electricity to customers.
	Other Operating Costs	55000 Demand Mgt Incentive Allowance	This Functional Area includes activities that are undertaken in accordance with the criteria of the AER's Demand Management Incentive Allowance incentive scheme.
		55100 Non Network Alternatives	This Functional Area includes the ongoing operating expenditure required from implementing strategic projects (capital expenditure) that will defer and in some cases negate the need completely for major infrastructure projects of a more “traditional” nature. The advantages being less capital expenditure investment, and greater flexibility and response to the fluctuations in customer demand.
		56040 Guaranteed Service Levels	Compensation payments are made to customers under the Electricity Industry Code (Electricity Act 1994), Guaranteed Service Levels (GSLs). These GSLs are minimum service standards that our small customers will expect to receive from Ergon Energy. If we do not meet these GSLs, small customers will receive a GSL payment which is costed to this activity. Services covered by GSL's include connections, reconnections, disconnections, hot water supply, planned interruptions and duration or frequency of interruptions.
		Training	The training Functional Area represents time costed to training activities for field staff and apprentices.
		Redundancy Payments	The redundancy payments Functional Area are payments made to employees whose roles have been made redundant and are therefore entitled to a payment by Ergon Energy.
		Employees in Transition	The Employees in Transition Functional Area costs are attributable to employees of Ergon Energy whose positions have been made redundant but have chosen not to leave Ergon Energy; these employees are moved into a transitionary role while they are temporarily displaced.
		Liability claims - Self Insurance	The liability claims self-insurance Functional Area is the cost of self-insurance to cover Ergon Energy for the aggregated claims that fall below deductible amounts for public liability only.
		Parametric Insurance	The parametric insurance Functional Area are the costs associated with the market insurance instrument enabling efficient recovery of costs associated with major cyclone events. Ergon Energy has sourced a parametric insurance policy that provides a more effective and efficient risk mitigation against the damage or

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
			loss to network assets caused by high winds due to major cyclones.
		Distribution Call Centre	This Functional Area which will be new under the 2015-16 to 2019-20 CAM, represents the Call Centre costs relating to the engagement and interaction with Network customers via phone and email. Currently these costs are in the Customer Service and Billing Functional Area.
		55500 Non Proceeding NICW	The write-off of costs associated with capital projects initiated by the corporation which eventually do not proceed to completion and which accounting rules require those costs to be expensed. These costs may include but not limited to pre-approved investigative, concept and optionality costs.
		Market Transaction Centre	The Market Transaction Centre manages important information between customers, retailers and with the Australian Energy Market Operator's Market Settlement and Transfer Solution system.
Overheads		Accounts Payable	The accounts payable Functional Area is responsible for undertaking accounts payable functions, invoice payments, and corporate card administration.
		Administrative Support	The administrative support Functional Area provides direct administrative support to operations staff, work group leaders, transmission services, lines services, and generation crews located in Ergon Energy's service areas.
		Bad and Doubtful Debts	The bad and doubtful debt Functional Area is an allowance for the inability to collect all accounts receivable in full.
		Business Risk Management	The business risk management Functional Area is responsible for the assessment and mitigation of business risks including the procurement of insurance and management of insurance claims. Business risk management is responsible for providing strategic vision and direction in the management and ongoing improvement of the organisation's enterprise risk management, compliance and related corporate governance functions. The area is also responsible for the effective coverage of the organisation's insurable risks, including the ongoing negotiation of insurance cover with the view to optimising the value for money proposition for the organisation.
		Corporate Support	The corporate support Functional Area is responsible for strategic oversight of the business by the office of the Chief Executive, internal and external stakeholder engagement, the program governance and management of key strategic projects identified as high importance by the Senior Leadership Team, and associated change management and business improvement activities.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		Customer Service and Billing	The customer service and billing Functional Area is responsible for direct engagement with the customer for both the retail and network areas of Ergon Energy and includes the management of customer related queries and responses, customer billing, hardship requests, and late payment management.
		EECL unregulated support	The unregulated support Functional Area provides support services to the Isolated Systems. The Isolated Systems Group is responsible for generating electricity and maintaining or upgrading networks in remote areas and is a key part of Ergon Energy's service to regional Queensland. This team specialises in helping customers on remote and isolated networks to reduce their electricity consumption and/or reduce demand on the network, and reduce the cost of electricity generation (and therefore CSO). This is done via specific programs with a strong community and customer engagement approach. Our customers benefit through reduced bills and Ergon Energy benefits through reduced costs.
		Engineering Standards, Technology and Support	The engineering standards, technology and support Functional Area includes a range of critical support functions including operational technology, standards development, standards maintenance, controls systems, engineering and design as it relates to the distribution network.
		Finance	The finance Functional Area is responsible for providing internal financial support to Ergon Energy including taxation advice, asset accounting, financial accounting, commercial and business unit financial management support, board reporting, investment planning, and data analytics to support the strategy.
		Fleet	The fleet Functional Area is responsible for the financial management, purchasing, replacement and disposal of Ergon Energy's fleet and must ensure fleet compliance with the maintenance, environmental and safety obligations as required.
		Fleet Depreciation	The fleet depreciation Functional Area recovers the depreciation on Ergon Energy's fleet.
		Fleet Recovery	Recovery of fleet related costs and depreciation charged to operational and capital activities. The Fleet Recovery fully offsets the sum of the Fleet and Fleet Depreciation Functional Areas.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		Governance, Regulation and Compliance	The governance, regulation and compliance Functional Area manages the requirements of the Ergon Energy Board, monitors high-level compliance and audit functions across Ergon Energy, and manages the regulatory regime including management of network revenue targets and setting of network prices, managing retail CSO processes, providing reports to the regulators, and management of Ergon Energy's licenses. The cost of governance and the oversight of the Board of Directors are also included within this Functional Area.
		Human Resources	The human resources Functional Area provides a range of strategic and operational human resource advice. The human resources costs are associated with ongoing recruitment, attraction and retention strategies, the management of Ergon Energy's industrial relation requirements, organisation design support, and the provision of ongoing technical training. The training and development group is a large function delivering significant amounts of business critical training for front line service areas.
		IT and Communications	Provision of services by SPARQ Solutions of IT Support, telecoms, software maintenance, billing system support, and operational support for IT projects.
		Labour On-cost on Payroll Recovery	This is the payroll on-costs for the Payroll Accrual Functional Area only.
		Legal and Secretariat	The legal and secretariat Functional Area is responsible for providing legal support and ongoing secretarial functions to the Ergon Energy Board. Specifically the legal costs are associated with managing day to day legal functions and providing high level strategic advice, guidance and counsel to management and business units to achieve optimal outcomes in terms of legal risk profile and business objectives. The secretarial function is responsible in advising the board and individual directors on corporate governance principles and plans and the implementation of corporate governance programs across Ergon Energy as well as facilitating the flow of information from the Board to Ergon Energy.
		Major Projects	The major projects Functional Area is responsible for managing major new customer connections and all major projects over $5 million from concept planning through to delivery. Major projects costs are associated with strategic planning, concept design, project management, program integration, and managing contractors for the final delivery of large infrastructure projects.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		Metering Support	The metering support Functional Area provides a wide range of metering services including metering asset management, strategic metering and metering data services. The costs are associated with the resources required to support metering design, metering installation, meter data management, management of customer metering services including remote meter reading, and are responsible for liaising with AEMO and external service providers.
		Network Management	The network management Functional Area is responsible for the management and maintenance of the distribution network. The range of functions include the reliability and quality of the network, asset management services in each regional area, maintenance standards and refurbishment, concept design, cultural heritage and Environmental Services. All of these functions are required to maintain the safety and the reliability of the network.
		Network Operations Support	The network operations support Functional Area is responsible for delivering a broad range of network maintenance activities including responsive, preventative and augmentation support. Support costs represent those costs that cannot specifically be charged to activities to maintain and upgrade the network including fault response, disaster management, customer connections, lines and substation maintenance, and network augmentation (i.e. downtime for team briefings, safety meetings, and other non-productive time).
		Network Planning	The network planning Functional Area includes a broad range of planning activities including setting the network strategy in line with strategic forecasting, aligning distribution planning and sub transmission planning to the strategy, operations and includes a provision for SWER improvements.
		Network Safety	The Network Safety Functional Area develops and maintains safe work practices and procedures, manages the field assessment and compliance with safe work practices, and is responsible for maintaining a safe and secure operation of the distribution and sub-transmission network.
		Network Sustainability and Support	Network sustainability and support Functional Area is accountable for the establishment, development and management of non-regulated, non-traditional business within Ergon Energy. This includes the acquisition of new and emerging technologies and service solutions, alternate power generation, demand management, energy conservation, and business incubation and development.
		Network Systems Support	The network system support Functional Area uses SCADA and the communication systems to manage the operation of the high voltage network from two control centres - one in Townsville and one in Rockhampton. The group controls the switching of high voltage devices for planned work and unplanned response work on

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
			a 24 hour basis.
		OH&S	The OH&S Functional Area is responsible for delivering effective OH&S outcomes including the development of the OHS Management System, delivering behavioural safety programs, conducting investigations and audits, and outworking the corporation's Community Electrical Safety Awareness Plan. The Functional Area is also required to manage WorkCover claims, employee health, union consultation related to safety issues, worker rehabilitation, injury prevention and injury management.
		Other Support Costs	Miscellaneous corporate and centralised costs including payroll on-cost payments (such as payroll tax, workers compensation, annual leave expense, long service leave expense, superannuation payments) and on-cost recovery, FBT, Bonus payments, fees and registrations.
		Payroll	The payroll Functional Area includes the costs associated with the provision of payroll services to Ergon Energy's employees
		Payroll Accrual	The payroll accrual Functional Area is an expense that ensures the payroll at group level reflects the working days up to the end of financial year (i.e. 30 June).
		Procurement and Logistics	The procurement and logistics Functional Area is responsible for managing the material supply chain ensuring timely delivery, accurate forecasting, efficient purchase of material and logistical support to undertake customer works including maintaining inventory management systems and warehousing management.
		Property	The property Functional Area is responsible for facilities management of over 200 non-network properties, and includes management of the construction and redevelopment of non -network major and minor capital projects.
		Resource and Works Delivery	The Works Enablement Group enables delivery of the program of work for design, construction and maintenance of the network. This includes effective resource planning and works management that aims to maximise service delivery utilisation and efficiency.
		Shared Services	The shared services Functional Area provides travel services, records management, printing, postage and courier, and library (including corporate subscriptions) services to Ergon Energy employees.

Operating expenditure category	Operating expenditure sub category	Functional Area name	Description of Functional Area
		Stores On-cost Recovery	Recovery of procurement and logistics costs incurred in the handling and processing of stores inventory. This recovery offsets costs incurred primarily in the Procurement and Logistics Functional Area
		Telecommunications and Facilities	The telecommunications and facilities Functional Area is responsible for the development, management and operation of the telecommunications network and assets including management of the carrier network, and the ongoing operations, management and installations of telecommunication and fibre optic equipment (CNOC).
		IT Asset Charge	This charge from SPARQ Solutions to Ergon Energy is inclusive of depreciation on Ergon Energy assets held by SPARQ Solutions, plus the cost of capital relating to loan facilities established to purchase the assets. The Functional Area also includes the cost of non-capitalised project costs.