Step Changes for Operating Costs

31 October 2014

Contents

1 Introduction

In applying step changes to its operating expenditure, Ergon Energy has had regard to the Australian Energy Regulator's (AER) requirements for determining step changes to be added to or subtracted from its operating expenditure forecast as reflected in the Expenditure Forecast Assessment Guideline.

The following document describes the proposed step changes included in Ergon Energy's base step trend (BST) operating expenditure forecast for the regulatory control period 2015-20. For operating expenditure forecast purposes, Ergon Energy proposes step changes in relation to the areas described in the following table.

Step change (Unescalated $2012-13)	**Operating expenditure category**	**2015-16 ($m)**	**2016-17 ($m)**	**2017-18 ($m)**	**2018-19 ($m)**	**2019-20 ($m)**	**Total ($m)**
Non Network ICT	Other operating costs (overheads)	10.2	10.2	10.2	10.2	10.2	51.0
AEMO Testing Requirements - Metering Preventative	Maintenance	1.0	1.0	1.0	1.0	1.0	5.0
Non Network Alternatives	Other operating costs - Network overheads (SCS)	3.5	3.5	3.5	3.5	3.5	17.5
Total Step change		**14.7**	**14.7**	**14.7**	**14.7**	**14.7**	**73.5**

2 Non Network ICT

2.1 Proposed step change

The proposed step change relates to expenditure that is required in the regulatory control period 2015-20 and is not reflected in the 2012-13 revealed base year for BST forecasting purposes and includes:

- expenditure for the SPARQ Solutions Pty Ltd (SPARQ) support functions for ICT capital works that were approved in the regulatory control period 2010-15 but were delivered after the 2012-13 year
- expenditure for SPARQ support functions for ICT capital works that were in addition to the approved 2010-15 capital works program but were justified by cost benefit analysis undertaken by Ergon Energy.

2.2 Driver of Step Change

The driver of the step change is a change in operating environment.

2.3 Expenditure Category

The category of expenditure is other operating costs.

2.4 Justification of step change

The following information provides Ergon Energy's supporting details and rationale for the proposed step change.

REQUIREMENT	RESPONSE

Description of the step change.	The proposed step change relates to expenditure that is required in the regulatory control period 2015-20 that is not reflected in the 2012-13 base year for BST forecasting purposes and includes:
	• expenditure for the SPARQ support functions for ICT capital works that were approved in the regulatory control period 2010-15 but were delivered after the 2012-13 year, including:
	    • ICT Infrastructure, including the migration of data centres
	    • Work Force Automation, including the First Response and Customer Service works
	    • Core Central Network Asset Model and Network Model Integration
	    • Market Systems, including Salesforce

REQUIREMENT	RESPONSE

	• expenditure for SPARQ support functions for ICT capital works that were in addition to the approved 2010-15 capital works program but were justified by cost benefit analysis undertaken by Ergon Energy, including:
	  ◦ Business Intelligence and Visualisation
	  ◦ Investment Decision Support.

Detailed description of the driver of the step change.	The driver of the step change has been a change in operating environment, in particular: • for those programs that were approved in the regulatory control period 2010-15, the Queensland Government's Interdepartmental Committee (IDC) on Electricity Sector Reform caused a deferral of the programs, resulting in the required operating expenditure not occurring in the revealed base year for BST forecasting purposes • for those programs which were in addition to the programs approved in the regulatory control period 2010-15, the programs were developed to give the business the ability to cope with additional data and analytic requirements that were not included in the regulatory control period 2010-15 but were supported by a cost benefit analysis for the investment. Further detail to support the programs can be found in Ergon Energy's Forecast Expenditure Summary – Information Communication and Technology.
Detailed description of the projects incurring the proposed expenditure.	During the regulatory control period 2010-15 Ergon Energy has implemented the following new ICT functionality, the operating costs for which were not represented in the 2012-13 revealed base year: • Network customer information system (PEACE) • Core Central Network Asset Model and Network Model Integration • Work Force Automation (FFA) • Contact Centre Technology (CCT) • Data Centre centralisation • Business Intelligence & Visualisation (BI&V) • Investment Decision Support (IDS)

<table>
<tr><th>REQUIREMENT</th><th>RESPONSE</th></tr>
<tr><td>Year in which the expenditure is first incurred.</td><td> Increases in operating expenditure for the above works commenced in 2013-14 for Business Intelligence and Visualisation, Data Centre Migration and Investment Decision Support capabilities. Increases in operating expenditure are forecast to commence in 2014-15 for Network customer information system, Work Force Automation and Contact Centre Technology. </td></tr>
<tr><td>Breakdown of the expenditure for each year in the forecast period.</td><td><table>
<tr><th>Unescalated $2012-13</th><th>2015-16 ($m)</th><th>2016-17 ($m)</th><th>2017-18 ($m)</th><th>2018-19 ($m)</th><th>2019-20 ($m)</th><th>Total ($m)</th></tr>
<tr><td>Non Network ICT</td><td>10.2</td><td>10.2</td><td>10.2</td><td>10.2</td><td>10.2</td><td>51.0</td></tr>
</table></td></tr>
<tr><td>Demonstration of how the expenditure amounts have been calculated.</td><td>Details of the forecast expenditure requirements can be found in Ergon Energy's Forecast Expenditure Summary – Information Communication and Technology and Table 4 of the Ergon Energy ICT Plan 2015-20.</td></tr>
<tr><td>Cost benefit or comparable analysis.</td><td> Each program included in the Ergon Energy ICT Plan 2015-20 is subject to the Ergon Energy gated business case approval process and supported by a cost benefit analysis which quantifies the financial costs and benefits, assumptions made and sources of cost information used, options analysis and recommendations. In particular these programs are:
Network customer information system (PEACE).
Core Central Network Asset Model and Network Model Integration
Work Force Automation (FFA).
Contact Centre Technology (CCT).
Data Centre centralisation.
Business Intelligence & Visualisation (BI&V).
Investment Decision Support (IDS)
</td></tr>
</table>

REQUIREMENT	RESPONSE

Change in operating environment.	Ergon Energy confirms that:
	• the costs listed in the proposed step change relate both to support costs for:
	  • AER approved ICT works in the regulatory control period 2010-15 but not included in the revealed base year costs and
	  • individual programs where Ergon Energy has undertaken a cost benefit analysis
	• the costs listed in the proposed step change cannot be met from existing regulatory allowances or from other elements of the expenditure forecast for the regulatory control period 2015-20.

Demonstration that the proposed step change has not contributed to a double counting of cost.	Ergon Energy confirms that: • the proposed costs of the additional step change amount are not compensated through the output measure in the rate of change or accounted for in the forecast productivity growth • the additional proposed step change costs are efficient and either have a positive business case, or meet the National Electricity Rules (NER) objective to meet or manage the expected demand for standard control services and comply with applicable regulatory obligations or requirements associated with the provision of standard control services.
How the step change satisfies the opex objectives and criteria.	The proposed step change in expenditure is required to provide a level of ICT support necessary to meet and manage the expected demand for standard control services in the regulatory control period 2015-20 and comply with applicable regulatory obligations and requirements associated with the provision of standard control services. The expenditure for services is tested in the market via a panel arrangement and /or competitive tendering. As noted above, each program is subject to Ergon Energy's gated business case approval process.
Evidence that the need for the project or program has been endorsed through relevant governance arrangements.	The Ergon Energy ICT Plan is approved through Ergon Energy's Investment Review Committee process.

3 AEMO Testing Requirements - Metering Preventative

3.1 Proposed step change

This step change relates to Metering Preventative costs required to complete regulatory in-situ testing of metering installations not previously undertaken or incurred in the base year.

3.2 Driver of Step Change

The driver of the step change is a change in operating environment.

The change relates to regulatory testing of direct connected metering in a rolling program of in-situ testing in lieu of a periodic consolidated test program such as that being being conducted in the 2014-15 year and testing of metering at Bulk Supply (Wholesale) metering installations which are due every 10 years. Neither program is represented in 2012-13 base year for BST forecasting of operational expenditure.

3.3 Expenditure Category

The category of expenditure is network maintenance.

3.4 Justification of step change

The following information provides Ergon Energy's supporting details and rationale for the proposed step change.

REQUIREMENT	RESPONSE
Description of the step change.	This step change relates to Metering Preventative costs required to meet regulatory Meter Asset Maintenance testing requirements as specified in Chapter 7 of the National Electricity Rules for in-situ field testing of metering installations not undertaken or incurred in the base year. The expenditure is considered to be a step change under the BST methodology as the cost was not part of the operating expenditure for the base year and it is a recurrent operating cost for the next regulatory control period 2015-20. These charges have been classified under the Network Maintenance operating expenditure category. The step change is required to meet regulatory requirements for Ergon Energy's Meter Asset Maintenance Plan as approved by AEMO for the 2015-20 regulatory period. The operating expenditure relates to a rolling

<table>
<tr><th>REQUIREMENT</th><th>RESPONSE</th></tr>
<tr><td></td><td>test plan for in-situ compliance testing of direct connected meter families and High Voltage testing of instrument transformers which is required every 10 years.

The forecast charge for the works are $1.0 million for 2015-16.</td></tr>
<tr><td>Detailed description of the driver of the step change.</td><td>The step change will need to be implemented from 2015-16. The operating expenditure relates to costs to meet the testing requirements.

As a Metering Service Provider Ergon Energy is required to be accredited in accordance with NER 7.6 and fulfill the requirements specified in accordance with clause S7.6.1 (a) of the NER to be registered with AEMO in that capacity.</td></tr>
<tr><td>Detailed description of the projects incurring the proposed expenditure.</td><td>Not applicable, as this expenditure is not related to specific projects.</td></tr>
<tr><td>Year in which the expenditure is first incurred.</td><td>The step change expenditure is first required in the 2015-16 year.</td></tr>
<tr><td>Expenditure for each year in the forecast period.</td><td><table>
<tr><th>Unescalated $2012-13</th><th>2015-16 ($m)</th><th>2016-17 ($m)</th><th>2017-18 ($m)</th><th>2018-19 ($m)</th><th>2019-20 ($m)</th><th>Total ($m)</th></tr>
<tr><td>AEMO Testing Requirements</td><td>1.0</td><td>1.0</td><td>1.0</td><td>1.0</td><td>1.0</td><td>5.0</td></tr>
</table></td></tr>
<tr><td>Demonstration of how the expenditure amounts have been calculated.</td><td>Ergon Energy has assessed the impact of additional work effort to meet its testing obligations in the regulatory control period 2015-20 and estimates the additional costs of compliance with the requirements will amount to $1 million per annum from the 2015-16 year. In establishing this cost estimate Ergon Energy has used an estimate for in-situ testing for direct connect meter families and actual costs incurred for high voltage testing at similar installations. The requirements for in-situ direct connect meter family testing for 2015-20 cannot be established with certainty until the test results in 2014-15 are completed and analysed. Market rates to undertake in-situ testing requirements will also be established in the 2014-15 year.</td></tr>
</table>

REQUIREMENT	RESPONSE
Cost benefit or comparable analysis.	The expenditure will be incurred to meet compliance obligations for meter testing for Ergon Energy to maintain its AEMO accreditation as a Metering Provider (MP) Category B. As a result, Ergon Energy has not undertaken a cost benefit analysis as it sees this expenditure as necessary to fulfilling its accreditation obligations and does not consider that there are viable alternative options to undertaking the required testing work. .
Change in operating environment.	Ergon Energy is registered as a MP Category B under AEMO's Metering Service Provider Accreditation Procedure (Document No MT_MA1683) for Metering installations Type 1 to 6. Chapter 7 Clause 7.6.1(a) places obligations on Ergon Energy MP to perform inspection and maintenance testing requirements as set out in Schedule 7.3. Ergon Energy will incur expenditure during the regulatory control period 2015-20 to fulfill its obligations relating to the AEMO requirements however these costs are not included in the 2012-13 base year for BST forecasting purposes. Instrument Transformer testing associated with High Voltage Wholesale Metering points only occurs every 10 years and in-situ testing of direct connect meter families is being conducted in 2014-15. Based on the BST costing methodology neither program would be included in the base year for calculation of the forecast for the regulatory control period 2015-2020. The incremental costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts.
Demonstration that the proposed step change has not contributed to a double counting of cost.	Ergon Energy has not undertaken work or incurred expenditure related to this work within the base year costs used to prepare the BST forecast of operating expenditure in the regulatory control period 2015-20. As such, the costs included in the step change related solely to the additional work are not included elsewhere in the operating expenditure forecasts. Ergon Energy confirms that: • increased volume or scale is not compensated through the output measure in the rate of change • the increased regulatory burden over time is not accounted for in the forecast productivity growth
How the step change satisfies the opex objectives and criteria.	This step change expenditure is required to maintain compliance with AEMO's requirements for accreditation of a Metering Provider. The expenditure reflects the costs that Ergon Energy, as a prudent operator, would require to achieve the operating expenditure objectives.

REQUIREMENT	RESPONSE
Evidence that the need for the project or program has been endorsed through relevant governance arrangements.	The additional work effort for this step change has been identified and approved through Ergon Energy's Network Optimisation group program and the identified additional cost requirements are included in the approved operating expenditure forecast.

4 Non Network Alternatives

4.1 Proposed step change

The proposed step change for Non Network Alternatives costs relates to the forecast additional operating expenditure initiatives required by Ergon Energy to avoid augmentation capital expenditure, in particular through Demand Management. The proposed step change forecast relates to the required operating expenditure for sites where generation is run as an alternative to network augmentation and includes fuel costs, running and maintenance costs and certain customer contract costs.

4.2 Driver of Step Change

The driver of the step change is a capex/opex trade-off. Required expenditure for the Demand Management program in the regulatory control period 2015-20 is higher than the expenditure incurred in the 2012-13 base year for BST operating expenditure forecasting. The additional expenditure is required to support the Ergon Energy's Demand Management program aimed at reducing peak demand and additional augmentation capital expenditure.

4.3 Expenditure Category

The expenditure category is other operating costs.

The avoided capital expenditure relates to demand driven augmentation capital expenditure.

4.4 Justification of step change

The following information provides Ergon Energy's supporting details and rationale for the proposed step change.

REQUIREMENT	RESPONSE
Description of the step change.	The proposed step change for Non Network Alternatives costs relates to the forecast additional operating expenditure initiatives required by Ergon Energy to avoid or defer augmentation capital expenditure, in particular through Demand Management. The proposed step change forecast costs relate to the required operating expenditure for Demand Management, for example for sites where generation is run as an alternative to network augmentation and include fuel costs, running and maintenance costs and certain customer contract costs.

<table>
<tr><th>REQUIREMENT</th><th>RESPONSE</th></tr>
<tr><td>Detailed description of the driver of the step change.</td><td>Ergon Energy implements Non Network Alternatives including Demand Management as a means of avoiding or deferring augmentation capital expenditure where it is cost effective to do so.

In implementing its Demand Management program Ergon Energy will incur operating costs associated with the activities described in its Demand Management 2015-20 document and avoid or defer augmentation capital expenditure.</td></tr>
<tr><td>Detailed description of the projects incurring the proposed expenditure.</td><td>The key programs included in the forecast for the proposed step change to be undertaken during the regulatory control period 2015-20 are the Network Constraint & Targeted Program.

Further details of the programs are available in the Ergon Energy Demand Management 2015-20 document.</td></tr>
<tr><td>Year in which the expenditure is first incurred.</td><td>The step change expenditure is first required in the 2015-16 year.</td></tr>
<tr><td>Breakdown of the expenditure for each year in the forecast period.</td><td><table>
<tr><th>Unescalated $2012-13</th><th>2015-16 ($m)</th><th>2016-17 ($m)</th><th>2017-18 ($m)</th><th>2018-19 ($m)</th><th>2019-20 ($m)</th><th>Total ($m)</th></tr>
<tr><td>Non Network Alternatives</td><td>4.0</td><td>4.0</td><td>4.0</td><td>4.0</td><td>4.0</td><td>20.0</td></tr>
<tr><td>Reallocation of Embedded Generation</td><td>(0.5)</td><td>(0.5)</td><td>(0.5)</td><td>(0.5)</td><td>(0.5)</td><td>(2.5)</td></tr>
<tr><td>Net outcome</td><td>3.5</td><td>3.5</td><td>3.5</td><td>3.5</td><td>3.5</td><td>17.5</td></tr>
</table></td></tr>
<tr><td>Demonstration of how the expenditure amounts have been calculated.</td><td>The cost build up methodology to support the Non Network Alternatives program is described in Ergon Energy’s Demand Management 2015-20 document.</td></tr>
</table>

REQUIREMENT	RESPONSE
Cost benefit or comparable analysis.	Ergon Energy's Demand Management 2015-20 document describes its program of Non Network Alternatives. The document describes the costs and benefits that underpin the proposed program of Non Network Alternatives, including the quantification of financial costs and benefits of the program of Non Network Alternatives. The document outlines the individual projects that are forecast to commence during the regulatory control period 2015-20 or are under investigation for commencement in 2015-20. All projects will be managed through the Ergon Energy gated business case process which reviews individual project costs and benefits and ensures that network risk justifies the investment in demand management for the forecast projects. The gated business case process conducts and analysis of a range of viable options and scenarios for each project investment.
Capex / opex trade-off.	Ergon Energy's Demand Management 2015-20 document describes and confirms: • the opex category (other operating costs) and the related capex category (augmentation capital expenditure) that are impacted by the proposed step change • the Non Network Alternative programs and associated costs of the related capital deferrals • the efficient costs associated with making the step change • that the proposed costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts.
Demonstration that the proposed step change has not contributed to a double counting of cost.	Ergon Energy confirms that the proposed increased expenditure in Non Network Alternatives: • is not compensated through the output measure in the rate of change • is not accounted for in the forecast productivity growth • is efficient and does not have a net negative impact on expenditure.

REQUIREMENT	RESPONSE
How the step change satisfies the opex objectives and criteria.	Ergon Energy's Non Network Alternative program assists Ergon Energy to meet and manage its expected demand for standard control services by providing cost effective solutions for managing peak demand at system and localised network levels. The program assists Ergon Energy in ensuring that augmentation capital expenditure is only progressed in areas where it is not prudent and efficient to implement a Non Network Alternative.
Evidence that the need for the project or program has been endorsed through relevant governance arrangements.	Ergon Energy's Demand Management 2015-20 document forms part of the suite of regulatory proposal documents and is subject to Ergon Energy's governance process for the submission of its regulatory proposal 2015-20.