ENERGEIA

Review of Victorian Distribution Network Service Provider's Advanced Metering Infrastructure Budget Applications 2012-15

Prepared by ENERGEIA for the Australian Energy Regulator

October 2011

1 Executive Summary

The Australian Energy Regulator (AER) engaged Energeia Pty Ltd (Energeia) to undertake a limited review of Victorian Distribution Network Service Provider's (DNSPs) 2012-2015 budget proposals for Advanced Metering Infrastructure (AMI) against the regulatory criteria specified in the revised Order in Council (OIC).

Review Scope

The scope of Energeia's review has been limited due to time constraints to focus on expenditure modified by the AER in its Draft Determination and subsequently contested by the DNSPs, and excludes consideration of any contested expenditure under the competitive tendering test of contracted expenditure.

Contested expenditure specifically agreed with the AER as being out of scope for Energeia's review includes two-element meters, related party margins, foreign exchange, Weighted Average Cost of Capital (WACC), and equity-raising costs and charges.

Review Approach

Energeia's approach to meeting the AER's requirements as described in their Request for Proposal (RFP) was to:

- develop an appropriate approach to apply the regulatory tests,
- review the AER's Draft Determination,
- review the relevant sections of each DNSP's initial and amended budget proposals, and
- review each DNSP's response to AER questions.

Based on the results of its initial review of the budget proposals, Energeia would:

- identify areas where the proposals may not meet the tests,
- develop questions which may help clarify the area of concern,
- undertake independent research, analysis and modelling, and
- if required, assist the AER in developing an alternative budget proposal.

Energeia's assessment of individual DNSP proposals against the relevant regulatory tests in the revised OIC was based on the approach outlined in the AER's Framework and Approach (AFA) paper.[1]

Our approach has also been informed by the AER's more recent application of the Commercial Standard test as set out in its Draft and Final Determination of SP AusNet's Revised Budget Application 2009-11.[2]

Resolving Issues

Where DNSP's Amended Budget Applications and Draft Determination responses did not contain sufficient information for Energeia to form a view as to whether they met the particular regulatory test, Energeia developed questions to address its specific areas of concern.

DNSPs were each sent 45-55 questions to address these issues, with a requirement to respond within the minimum three business days due to tight timeframes. Energeia considered each DNSP's response, contacting them directly via telephone to address any remaining questions.

[1] Final Decision – Framework and approach paper Advanced metering infrastructure review 2009-11, AER, January 2009.
[2] Draft Determination – SP AusNet AMI Revised Budget Application 2009-11, April 2011.

Energeia acknowledges the pressure these requests put on each DNSP, and would like to thank their regulatory managers in particular for their understanding, support and cooperation.

Review Findings

Energeia reviewed over a hundred documents totalling over 2,000 pages from the DNSP's in support of their Amended Budget Applications. The result of our assessment of in-scope expenditure against each of the given regulatory tests is shown in Table 1.[3]

Table 1 – Expenditure Assessment Summary

	SPN	PAL	CP	UED	JEN
Scope Test					
Meter Volumes	X	X	X		
Expenditure Incurred Test					
Communications Network Augmentation Costs				✓	✓
AMI Technology and Vendor Management Costs				✓	✓
Stakeholder Relations Costs				✓	✓
Call Centre Costs		✓	✓		
Customer Interactions Costs		✓	✓		
AMI Data Delivery Costs		✓	✓		
AMI Technology Acceptance Costs		✓	✓		
Commercial Standard Test					
Meter Capex	X				
IT Opex	X				
Meter Data Management Opex	✓				
Meter Maintenance Opex	✓				
Communications Infrastructure Opex	X				
Project Management Opex	X				
Installation Capex				✓	✓
New Connections Capex				X	X
AMI Technology and Communications				✓	✓
IT Infrastructure and Systems Capex				✓	✓
Second Meter Supplier				X	
Asset Strategy and Planning Capex				✓	✓
Meter Supply – 'Other Costs'		X	X		
Meter Installation – 'Other Costs'		X	X		
Communication Equipment Supply – 'Other Costs'		✓			
Communication Equipment Installation – 'Other Costs'		✓	✓		
IT Capital Expenditure		✓	✓		
Meter Data Services		✓	✓		
Communication Operations		✓	✓		

Based on our review of information provided by the DNSPs and independent investigations, Energeia believe that the proposed budgets can, in most of the cases we have been able to investigate in the timeframe allowed, be reasonably attributed to material changes in their regulatory obligations under the OIC.

Moving an industry to a new frontier of technical performance, and being the first in the world to do so, is not without significant cost and risk. Energeia expects these costs and risks to abate over time as the industry matures, with significant but as yet unrealised benefits ultimately flowing to Victorian consumers.

[3] Only expenditure assessed as entirely meeting the test is indicated by a green tick.

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Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon regulatory guidance from the Australian Energy Regulator (AER) and information provided by the Distribution Network Service Providers (DNSPs), including third party consultants. To the extent these reliances have been made, Energeia does not guarantee or warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party should use or rely on the report for any purpose.

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2 Background

The Victorian Government announced the rollout of Advanced Metering Infrastructure (AMI) for all customers consuming less than 160MWh per annum in 2006. The Government subsequently decided that electricity distributors would be given an exclusive mandate to roll out the meters.

The regulatory arrangements relating to the rollout are set out in an August 2007 Order in Council (OIC) made under sections 15A and 46D of the Electricity Industry Act 2000, and an amending order made on 25 November 2008 (The 'revised OIC').

The revised OIC sets out the regulator's role and is the primary regulatory instrument which guides the determination of revenue and prices for metering services.

The revised OIC requires the Australian Energy Regulator (AER) to determine if the activities proposed by Distribution Network Service Provider's (DNSP's) to deliver AMI services over the period 2012-15 are required to deliver the specified AMI services. Although there is no efficient costs review of the distributors' budgets, the AER may nevertheless reject a budget application, or part thereof, if it determines that the activities, or part thereof, are not required to deliver AMI services, or that the costs will not be incurred by the DNSP to deliver those services, or that a reasonable commercial business would not commit to such expenditure if placed in the DNSPs' shoes.

The revised OIC requires the AER to make a Final Determination on the DNSP's subsequent AMI budget and charges applications for 2012-15 by 31 October 2011.

3 Overview

The AER engaged Energeia Pty Ltd (Energeia) to undertake a limited, four week review of Victorian DNSPs' 2012-2015 budget proposals for AMI against the regulatory criteria outlined in Section 5.

Energeia's assessed 27 contested expenditure items by reviewing DNSP supplied information against the regulatory criteria, working closely with the AER to resolve any information gaps. Energeia's review considered a number of detailed cost modelling spreadsheets and over one hundred documents totalling over 2,000 pages provided by DNSPs in support of their proposals.

This report documents the approach and outcomes of Energeia's review of DNSP costs against the specified regulatory criteria.

4 Review Scope

The scope of Energeia's review has been limited due to time constraints to focus on expenditure modified by the AER in its Draft Determination and subsequently contested by the DNSPs, and excludes consideration of contested expenditure under the competitive Competitively Tendered test.

Contested expenditure specifically agreed with the AER as being out of scope for Energeia's review includes two-element meters, related party margins, foreign exchange, Weighted Average Cost of Capital (WACC), and equity raising cost and charges.

Energeia reviewed DNSP's in-scope costs against the following revised OIC[4] tests:

> 5C.2 The Commission must approve the Submitted Budget unless the Commission establishes that the expenditure (or part thereof) that makes up the Total Opex and Capex for each year:
>
> (a) is for activities outside scope at the time of commitment to that expenditure and at the time of the determination; or
>
> (b) is not prudent.

The test for scope is provided in *Clause 2 – Definitions* and *Schedule 2*[5] of the revised OIC:

> "**scope**' means the scope of activities:
>
> (a) set out in Schedule 2; or
>
> (b) published pursuant to clause 14B
>
> as amended from time to time.'

The tests for prudency are provided in Clause 5:

> 5C.3 For the purposes of clause 5C.2(b), expenditure is prudent and must be approved:
>
> (a) where that expenditure is a contract cost, unless the Commission establishes that the contract was not let in accordance with a competitive tender process; or
>
> (b) where that expenditure:
>
> (i) is not a contract cost; or
>
> (ii) is a contract cost and the Commission establishes that the contract was not let in accordance with a competitive tender process,
>
> unless the Commission establishes that:
>
> (iii) it is more likely than not that the expenditure will not be incurred; or
>
> (iv) the expenditure will be incurred but incurring the expenditure involves a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.
>
> 5C.4 For the purposes of clause 5C.3(b)(iv), the Commission must take into account and give fundamental weight to the matters referred to in clause 5I.8, with all necessary changes being made.
>
> ---

[4] Victoria Government Gazette, No. S 314, Victorian Government Printer, 25 November 2008.

[5] Schedule 2 is not reprinted here due to its length

5I.8 For the purposes of making a determination pursuant to paragraph 5I.7(b), the Commission shall take into account and give fundamental weight to:

(a) the circumstances of the distributor;

(b) if the distributor did not directly incur the expenditure, the circumstances of the person that did incur it; and

(c) if the distributor did not directly manage the expenditure, the circumstances of the person that did manage it,

at the time the commitment was made to incur or manage (as the case may be) the expenditure excess including:

(d) the information available at that time;

(e) the nature of the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;

(f) the nature of the rollout obligation;

Note: See clause 14 and Schedule 1.

(g) the state of the technology relevant to the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;

(h) the risks inherent in a project of the type involving the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;

(i) the market conditions relevant to the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems; and

(j) any metering regulatory obligation or requirement.

Where costs failed the regulatory tests, Energeia was to assist the AER with the development of a new Submitted Budget as follows:

5C.5 The Commission must make a draft determination approving or rejecting the Submitted Budget. If the Commission determines to reject the Submitted Budget:

(a) the Commission must in its reasons state what new Submitted Budget it would determine to approve; and

(b) the distributor must within 20 business days make application to the Commission for approval of an amended Submitted Budget.

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5C.8 In making a determination under clause 5C.5(a) or clause 5C.7 (as the case may be), the Commission's discretion is limited to stating the new Submitted Budget or determining an Approved Budget (as the case may be) that removes not more than the expenditure it has established under clause 5C.2 as being:

(a) for activities outside scope at the time of commitment to that expenditure and at the time of the determination; or

(b) not prudent.

In addition, the review examined particular questions raised by the AER, as notified from time to time.

4.1 Out of Scope

The following costs are out of scope for Energeia's limited review of DNSP's amended 2012-15 budget and charges applications:

- Assessment of approved DNSP's costs for 2012-15
- Assessment of newly proposed DNSP costs for 2012-15
- Assessment of the efficiency of DNSP costs
- Assessment of two-element meters costs
- Assessment of related party margin costs
- Assessment of foreign exchange costs
- Assessment of the Weighted Average Cost of Capital (WACC)
- Assessment of equity raising cost
- Assessment of DNSP 2012-15 charges applications

5 Review Approach

Energeia's approach to satisfying the AER's requirements as described in their Request for Proposal (RFP) was to:

- develop an appropriate approach to apply the regulatory tests,
- review the AER's Draft Determination,
- review the relevant sections of each DNSP's initial and amended budget proposals, and
- review each DNSP's response to AER questions.

Based on the results of its initial review of the budget proposals, Energeia would:

- identify areas where the proposals may not meet the tests,
- develop questions which may help clarify the area of concern,
- undertake independent research, analysis and modelling, and
- if required, assist the AER in developing an alternative budget proposal.

The following sections detail Energeia's approach to reviewing and testing the proposals, including resolving any issues.

5.1 Tests

Energeia's based its approach to applying the regulatory tests on the AER's Framework and Approach[6] (AFA), Draft Determination[7] and discussions with AER staff during the review. The testing steps and sequence involved are reflected in the AER's Draft Determination illustration, reproduced in Figure 1 below.

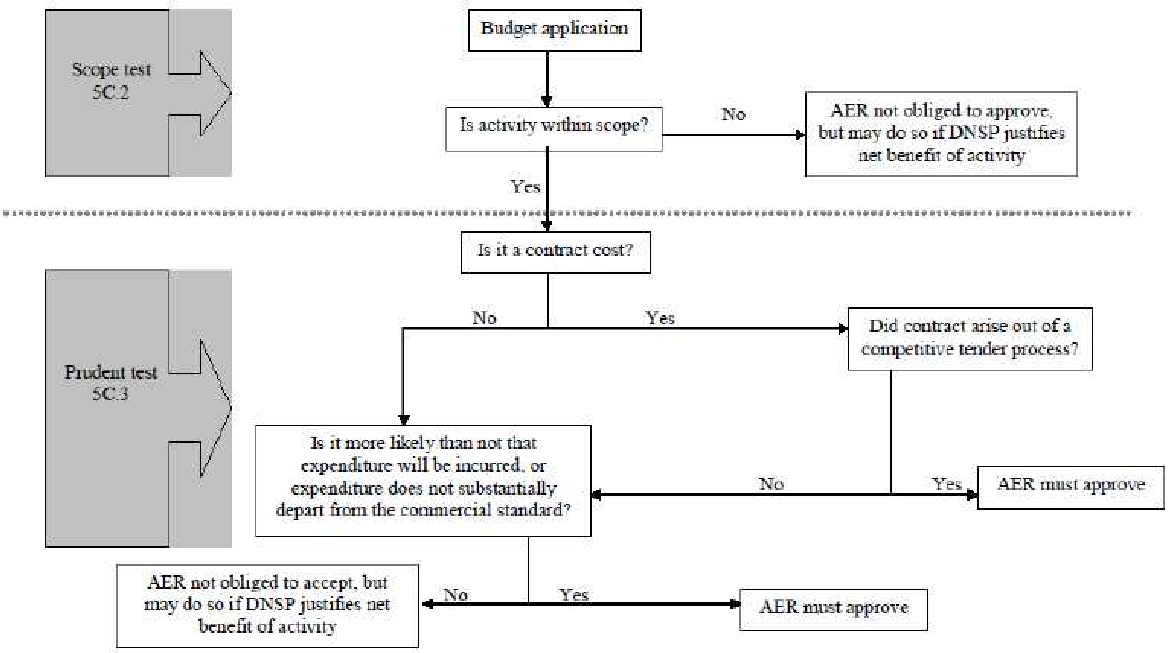

Figure 1 – Expenditure Testing Process

Energeia's approach to each test under the revised OIC is provided below.

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[6] Final Decision – Framework and approach paper Advanced metering infrastructure review 2009-11, AER, January 2009.

[7] Draft Determination – Victorian AMI Review 2012-15 budget and charges applications, AER, 28 July 2011.

5.1.1 Scope

The AFA, electricity distribution business experience and AMI technical expertise were taken into consideration when applying the scoping criteria under Section 2.1 of the revised OIC:

> "**scope**' means the scope of activities:
>
> (a) set out in Schedule 2; or
>
> (b) published pursuant to clause 14B
>
> as amended from time to time.'

When reviewing DNSP proposals against theses scoping tests, Energeia adopted the following approach per Section 2.5.2 the AFA (not necessarily in sequential order):

> In establishing whether expenditure is within scope the AER will be applying the definition of scope in the revised Order. The AER agrees that the test is based on the definition and that Schedule 2 lists activities which are agreed to be inside or outside scope. Activities not on Schedule 2 may be within scope, or not, based on whether they are reasonably required for the provision of regulated services and to comply with a metering regulatory obligation or requirement.
>
> ...
>
> It will apply this test by seeking to understand how the expenditure proposed relates to the activities being undertaken, and how these activities relate to the scope, based on the definition and having regard to Schedule 2.
>
> ...
>
> In considering the matter of scope it is also necessary to take into account the relevant specifications for providing the services. For performance in excess of the minimum Victorian specifications, distributors will need to provide a separate cost/benefit analysis quantifying benefits to the distributor, retailers and end customers, and demonstrating why regulated tariffs should provide the revenue required.

When considering this last paragraph on the review, Energeia would have regard to Clause 2.1 of the original OIC[8] (not in sequential order):

> "**Functionality Specification**" means the minimum State-wide functionality requirements and performance levels set out in sections 3 and 4, respectively, of the document entitled "Minimum AMI Functionality Specification (Victoria)" approved by the Minister and published on the Department's website on 18 October 2007, as amended in accordance with clause 6 from time to time.
>
> ...
>
> "**Service Levels Specification**" means the services and minimum service levels set out in section 4 of the document entitled "Minimum AMI Service Levels Specification (Victoria)" approved by the Minister and published on the Department's website on 18 October 2007, as amended in accordance with clause 6 from time to time.
>
> "**Specifications**" means the Functionality Specification and the Service Levels Specification.
>
> ...

[8] Victoria Government Gazette, No. S 286, Victorian Government Printer, 12 November 2007

Subordinate Instrument provision	Title of Document	Matter in document
Clause 2.1, definition of "Functionality Specification"	Minimum AMI Functionality Specification (Victoria)	Sections 3 and 4
Clause 2.1, definition of "Service Levels Specification"	Minimum AMI Service Levels Specification (Victoria)	Section 4

5.1.2 Costs Likely to be Incurred

AFA Section 2.5.5, electricity distribution business experience and budget development expertise were taken into account when assessing whether it was more likely than not that non-contract expenditure would not be incurred under Section 5C.3(b)(iii) of the revised OIC.

Energeia's approach to applying this test is based on Section 2.5.5 of the AFA, which focused on identifying contingency costs which are unlikely to occur:

- where expenditure on a specific cost item is not likely to be incurred to any extent. For example, this might include a contingency amount which the regulator considers is not likely to eventuate

- where expenditure on a specific cost item is not likely to be incurred to any extent. For example, this might include a contingency amount which the regulator considers is not likely to eventuate

Energeia sought to apply this test by identifying inappropriate, inaccurate and unreliable cost estimating practices. The level and quality of business planning and support of key cost driver assumptions were therefore taken into consideration when applying this test, particularly where estimates were developed internally without a historical cost basis and little or no previous experience with the activity or technology.

5.1.3 Substantial Departure from a Commercial Standard

AFA Section 2.5.6, electricity distribution business experience and commercial expertise were taken into account when assessing whether incurring a non-contract cost would involve a substantial departure from the commercial standard by a reasonable business in the circumstances under Section 5I.8 of the revised OIC.

Due to the relatively limited number of relevant industry examples and publically available information available for determining the commercial standard, Energeia sought in most cases to establish the Victorian standard using DSNP supplied information. DNSP's performance against this standard was then assessed, taking into account the specific circumstances required under the revised OIC.

Expenditure would be deemed to be a substantial departure from the commercial standard if it could be established that an alternative approach would be likely to result in a substantially lower risk adjusted cost, taking all circumstantial criteria listed in the revised OIC Section 51.8 into account.

Expenditure might also be deemed to be a substantial departure from the commercial standard if it could be established that the expenditure was substantial in terms of cost or risk, and it could not be established that a reasonable level of commercial consideration had been undertaken in support of it.

5.2 Resolving Issues

Where DNSP's Amended Budget Applications and Draft Determination responses did not contain sufficient information for Energeia to form a view as to whether they met the particular regulatory test, Energeia developed questions to address its specific areas of concern.

6 Review Outcomes

Energeia reviewed over a hundred documents totalling over 2,000 pages from the DNSP's in support of their Amended Budget Applications. The result of our assessment of in-scope expenditure against each of the given regulatory tests is shown in Table 1.[9]

Table 1 – Expenditure Assessment Summary

	SPN	PAL	CP	UED	JEN
Scope Test					
Meter Volumes	X	X	X		
Expenditure Incurred Test					
Communications Network Augmentation Costs				✓	✓
AMI Technology and Vendor Management Costs				✓	✓
Stakeholder Relations Costs				✓	✓
Call Centre Costs		✓	✓		
Customer Interactions Costs		✓	✓		
AMI Data Delivery Costs		✓	✓		
AMI Technology Acceptance Costs		✓	✓		
Commercial Standard Test					
Meter Capex	X				
IT Opex	X				
Meter Data Management Opex	✓				
Meter Maintenance Opex	✓				
Communications Infrastructure Opex	X				
Project Management Opex	X				
Installation Capex				✓	✓
New Connections Capex				X	X
AMI Technology and Communications				✓	✓
IT Infrastructure and Systems Capex				✓	✓
Second Meter Supplier				X	
Asset Strategy and Planning Capex				✓	✓
Meter Supply – 'Other Costs'		X	X		
Meter Installation – 'Other Costs'		X	X		
Communication Equipment Supply – 'Other Costs'		✓			
Communication Equipment Installation – 'Other Costs'		✓	✓		
IT Capital Expenditure		✓	✓		
Meter Data Services		✓	✓		
Communication Operations		✓	✓		

In addition to assessing specific in-scope expenditure items against the given test, Energeia also undertook a broad review of DNSP's proposed opex. This was meant to address the incentives outlined above, and to compliment the broad capex review Energeia had undertaken as part of the 2009-11 review.

[9] Only expenditure assessed as entirely meeting the test is indicated by a green tick.

DNSPs face a number of sometimes conflicting incentives and constraints that affect their decision making processes and behaviour. Key incentives driving DNSP behaviour with respect to opex in the 2012-15 AMI Budget Applications include:

- the revised OIC cost pass-through mechanism and allowance of up to a 10% variation in approved expenditure prior to becoming subject to a regulatory review, and
- the Efficiency Benefits Sharing Scheme (EBSS), which is designed to reward DNSPs for reducing their OPEX below forecasted levels (e.g. by reducing their controllable operating costs).

The revised OIC cost pass-through mechanism and variation allowance does not provide an incentive to operate efficiently, though there is the risk that the AER could cut proposed expenditure under the Commercial Standard test.

Instead, the revised OIC introduces an incentive for DNSPs to overstate opex in order to reduce the risk of a future AER review, because the higher the approved OPEX budget (relative to actual costs), the lower the likelihood of breaching the variation limit.

The currently proposed AMI expenditure will not be subject to the EBSS or any other incentive mechanism under the revised OIC. However, an EBSS is expected to apply from 2015 under the next Determination. Businesses will benefit where they are able to sustainably cut AMI related opex from 2015.

The higher the Opex allowed in 2015 relative to sustainably efficient levels, the greater the commercial reward will be for DNSPs that deliver sustainably efficient opex once under the EBSS.

Energeia's review of DNSP's overall opex budgets focused on the 2015 timeframe as this was the year when all establishment related activity should be completed, and the businesses should be operating in a BaU mode. Energeia examined each business before and after AMI, in terms of organisation and opex, and attempted to identify major impacts (both negative and positive) that could drive significant changes in costs.

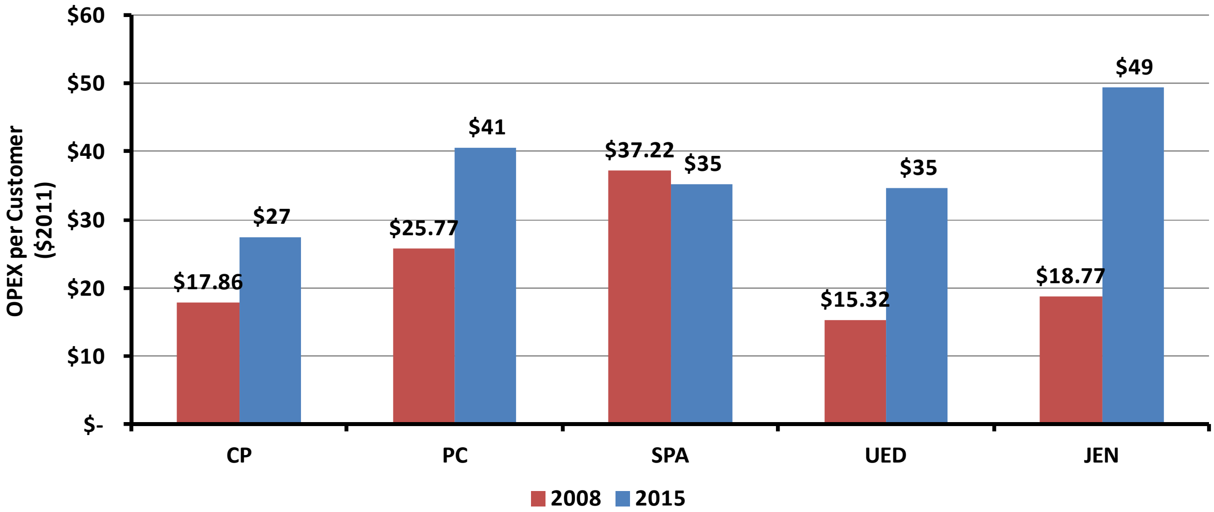

Figure 2 – DNSP Metering Operational Expenditure in 2008 and 2015

Figure 2 compares DNSP's proposed total opex per customer in 2015 relative to its allowed metering opex in 2008 under the previous Victorian Essential Services Commission's (ESC) 2005 determination.[10] The comparison reveals a 63% increase on average in metering related opex over the period.

[10] Electricity Distribution Price Review 2006-10, Victorian ESC, October 2005.

Based on our independent investigation of industry costs and impacts, and review of information provided by the DNSPs in response to our specific questions, we believe that the proposed budgeted increases can, in the cases we have been able to investigate, be reasonably attributed to material changes in their regulatory obligations under the revised OIC. There are a few mostly minor exceptions that are detailed in the following sections.

Moving an industry to a new frontier of technical performance, and being the first in the world to do so, is not without significant cost and risk. However, Energeia expects these costs and risks to abate over time as the industry becomes more mature.

Driven by the EBSS, and supported by growing organisational experience and technology maturity, Energeia expects DNSPs will find ways to reduce their AMI cost structures over time. However, based on the experience of other trailblazing businesses in Australia and overseas, one to two years out is still an insufficient timeframe for assuming that AMI related processes and resourcing levels will be bedded down.

Ausgrid deployed over 200,000 manually read interval meters nearly four years ago, and continues to grapple with premature failure of segments of its electronic metering asset fleet, the performance of its meter reading technology, and the quality of its interval data to market.

The results of Energeia's assessment of DNSP's in-scope expenditure against the relevant regulatory tests are detailed in following sections.

6.1 Scope

The following DNSP costs were assessed against the scoping criteria set forth in the revised OIC.

6.1.1 Meter Volumes

The AER in its Draft Determination found that meter volumes proposed by the businesses did not appropriately account for re-use of meters, and that the forecast number of meters therefore included quantities in excess of requirements, which would be out-of-scope under the revised OIC.[11]

JEN and UED (JEN-UED) accepted the AER's meter volume adjustments. CitiPower and Powercor (CP-PAL) revised their forecasts in their amended budgets to account for re-use of meters from supply abolishments and customer requested changes to metering installations.

Energeia reviewed the responses of CP-PAL and SP AusNet to assess whether their forecasts were based on:

- Net customer growth forecasts consistent with their most recent Determination
- Historical rates of supply abolishments, meter alterations or additions
- Average ratio of meters to customers based on AMI deployment data to date
- Percentage of AMI meters to non-AMI meters

Energeia requested further information from CP-PAL and SP AusNet in support of their historical rates of abolishment and their forecasts of net new customers. Energeia also requested confirmation that two element AMI meters could be reprogrammed to be used as a single element meter, which meant that they did not need to be discarded if two element meters were phased out in the future.

CP-PAL provided their historical rates of supply abolishments, alts and adds, and demonstrated that their forecast of net new customer growth is based on an independent expert forecast. They also affirmed that two element meters could be reprogrammed to be single element meters, implying these could be re-used.

[11] See pages 48-49 of the Draft Determination

Energeia's review of CP-PAL's customer growth rates has found that CP-PAL have used the relatively lower 2010 actual number as the projection for the 2011-15 period, rather than using an average of the 2009-10 period.[12] This results in a 5-14% greater new meter requirement and commensurately lower meter recertification cost, which on balance results in a higher overall cost estimate.

Energeia has also found that CP-PAL's assumption that 1.5% of removed two element meters will not be able to be re-used is incorrect as these meters may be reprogrammed and re-used as single element meters. Energeia's view is that CP-PAL's assumption of non-reusable AMI meters should be reduced from 2% to 0.5% to reflect the potential re-use of two element meters.

SP AusNet did not provide a detailed response in support of their approach to forecasting net customer additions. According to SP AusNet, it 'did not mirror the increase in customer numbers in the EDPR', though SP AusNet claim it was calculated on a consistent basis. No evidence was provided in support of this claim.

Energeia's review of SP AusNet's forecast customer growth rates in 2014-15, when data is available that is net of abolishments, has found that SP AusNet's assumed customer growth rates appear to be 20% higher than the number used and independently verified in their revised EDPR submission.

Based on its review of DNSP provided documentation and supporting information, Energeia assessed a portion of CP-PAL's proposed meter supply costs as meeting the Scope test.

Based on its review of DNSP provided documentation and supporting information, Energeia assessed a portion of SP AusNet's proposed meter supply costs as meeting the Scope test.

6.2 Incurring Costs

The following DNSP costs were assessed against the expenditure Incurred test set forth in the revised OIC.

6.2.1 JEN and UED

6.2.1.1 Network Augmentation

The AER in its Draft Determination found that JEN and UED's proposed network augmentation expenditure was already recovered under information technology (IT) expenditure and was therefore unlikely to be incurred twice.[13]

JEN and UED argued that the expenditure related to the ongoing optimisation and development of the AMI Local Area Network (LAN), was not already included as IT expenditure, and was therefore likely to be incurred.[14]

In support of their claim, JEN and UED provided a report by KEMA, who is the independent expert paid by the JEN-UED AMI program to perform a quality assurance role, to review the expenditure against the Incurred Test. KEMA's report found that the expenditure met the Incurred test.[15]

In its discussion of the proposed expenditure, KEMA states that they 'address the need to complete the build out of initial communication infrastructure. As the mass deployment of meters winds down, there will [be] unique and/or hard to reach areas left to cover. This work ensures that all of the meters will be ensured connectivity by 2013.' It is also required to support ongoing network augmentation over time.

[12] See pages 2-3 of CP-PAL's response to AER Questions of 2 September 2011
[13] See page 79 of the Draft Determination
[14] See pages 39-41 of the JAM Draft Determination response
[15] See page 19 of the KEMA report

Energeia's review has found that JEN and UED's proposed expenditure on network augmentation meets the Incurred test. This is based on JEN and UED's initial need to address the expected 1% gap in network coverage by 2013 expected under its contracted performance levels, and to address gaps that emerge over time due to customer growth. The expenditure is likely to be incurred because failing to invest is likely to result in JEN and UED being non-compliant with the Victorian minimum performance levels for collection of daily meter readings.[16]

Energeia notes that the proposed expenditure in 2014-15 appears to be based on unsupported assumptions. JEN-UED's assumed number of access points (AP) and relays installed per year under the network augmentation expenditure is between [C-I-C] and [C-I-C], which is about double the forecast used for meter supply.

However, given the nominal expenditure involved, and the fact that PAL have included a similar level of ongoing expenditure for network augmentation in their proposals, Energeia has found the expenditure is more likely than not to be incurred, and therefore meets the Incurred test.

Based on its review of DNSP provided information, Energeia assessed JEN and UEDs' network augmentation as meeting the Incurred test.

6.2.1.2 Management of Major AMI Releases and Vendors

The AER in its Draft Determination found that JEN and UED's proposed AMI technology and vendor management expenditure was already recovered under IT capex and was unlikely to be incurred twice.[17]

JEN-UED argued, via their shared service provider Jemena Asset Management (JAM), that the expenditure related to management of AMI technology and not IT technology, which starts after the enterprises services bus (ESB) at the network management system (NMS) interface and continues to the meter. The expenditure was complimentary, but separate and in addition to IT expenditure, and was therefore likely to be incurred.[18]

In considering whether JEN-UED's proposed expenditure related to managing AMI technology and vendors is likely to be incurred, Energeia reviewed the explanation provided by JAM in its response to the AER, and the level of proposed spending relative to the likely level of technology and vendor management activity.

Energeia's review found that JAM will need to manage changes to the AMI technology over time, and to manage the associated vendors in the process. This is in addition to the changes being managed by the IT group, which cover upstream systems.

Based on its review of DNSP provided information, Energeia assessed JEN and UED's technology and vendor management costs as meeting the Incurred test.

6.2.1.3 Stakeholder Relations

The AER in its Draft Determination found that JEN and UED's proposed stakeholder relations expenditure was already recovered under asset operations and management expenditure and was unlikely to be incurred twice.[19]

[16] See Page 3 of JEN response to Energeia questions
[17] See page 79 of the Draft Determination
[18] See pages 39-41 of JAM's Draft Determination Response
[19] See pages 79-80 of the Draft Determination

JAM argued that the expenditure related to industry, retailer and customer service related roles, and are in addition to the strategic stakeholder management related expenditure allowed for in the asset operations and management expenditure. Energeia notes that JEN-UED's proposed expenditure for these roles represents a partial allocation of costs.[20]

Energeia's assessment of whether the expenditure was likely to be incurred included consideration of Ausgrid's experience deploying smart metering in NSW, the fact that the roles exist and are performing the identified in-scope activities, and the expected ongoing level of stakeholder relations related activity.

Based on the Ausgrid experience, stakeholder management in each of the identified areas including strategic stakeholders is reasonable to expect. Failure to manage customers, retailers or industry arrangements can result in additional program risk and cost due to stakeholder resistance stemming from meter replacements, the assignment to ToU tariffs and necessary institutional development and reform.

Energeia notes that although the level of industry development has decreased with the winding down of the National Smart Meter Program (NSMP), stakeholder management related activity is likely to increase as installed meters are logically converted to fully functional AMI meters, remote and HAN related services are activated, and customers are transitioned on to ToU prices.

Based on the experience of Ausgrid, review of DNSP provided documentation and supporting information, Energeia assessed stakeholder relations costs as meeting the Incurred test.

6.2.2 CitiPower and Powercor

6.2.2.1 Call Centre Costs

The AER in its Draft Determination found that CP-PAL's proposed call centre expenditure was already recovered under AMI capex, and it was therefore more likely than not that the proposed expenditure would not be incurred twice.[21]

CP-PAL argued that the expenditure was related to the incremental cost of providing call centre service to support the rollout, had not already been included in AMI capex, and was therefore likely to be incurred.[22] They claimed that this could be verified by reviewing their opex and capex models.

Energeia's review considered the nature of CP-PAL's expenditure and their supporting information, including their costing models. Energeia's review found that CP-PAL's costs for call centre support did not appear to be recovered as part of their meter installation costs. Moreover, their activity assumptions are consistent with recent experience, and Energeia accepts them as reasonable.

Based on its review of DNSP provided information, Energeia assessed CP-PAL's call centre costs as meeting the Incurred test.

6.2.2.2 Customer Interactions

The AER in its Draft Determination found that CP-PAL's proposed customer interaction expenditure was already recovered under AMI meter installation expenditure, and it was therefore more likely than not that the proposed expenditure would not be incurred.[23]

[20] See pages 46-49 of JAM's Draft Determination Response

[21] See pages 81 of the Draft Determination

[22] See pages 52 of the PAL Draft Determination Response

CP-PAL argued that the expenditure was related to the cost of managing customer interactions during the meter rollout, had not already been included in meter installation capex, and was therefore likely to be incurred.[24] CP/PAL claimed that this could be verified by reviewing their capex and opex cost models.

Energeia's review considered the nature of CP-PAL's expenditure and their supporting information, including their opex and capex costing models. Energeia's review found that CP-PAL's costs for customer interactions did not appear to be recovered as part of their meter installation costs.

Energeia also found that the expenditure was for necessary in-scope activities under the revised OIC to avoid non-compliance related to statutory customer communications during the rollout, to manage customer service payments, and to manage customer complaints, including escalations to the industry ombudsman.

Based on its review of DNSP provided information, Energeia assessed CP-PAL's customer interaction costs as meeting the Incurred test.

6.2.2.3 AMI Data Delivery

The AER in its Draft Determination found that CP-PAL's proposed data delivery costs under its AMI communications expenditure was already recovered under its meter data management expenditure and it was therefore more likely than not that the proposed expenditure would not be incurred.[25]

CP-PAL argued that the expenditure was specifically related to the cost of operating and maintaining the communications network, had not already been recovered under meter data management opex, and was therefore likely to be incurred.[26] They supported their claim by engaging Deloitte, a professional services firm, to develop a bottom-up model of the costs involved.

Energeia's examination of CP-PAL's opex and capex models confirmed that the AMI communications expenditure related to different activities and resources to that of meter data management. The AMI communications opex in question relates to activities by CP-PAL's AMI communications control staff to ensure data is collected from the field and provided to the meter data management system. The meter data management costs relate to the cost of managing data exceptions and retailer queries.

Energeia also found the expenditure necessary to address meter data issues related to AMI communication system faults and defects. CP-PAL is therefore unlikely to avoid this cost without breaching their statutory performance targets.

Based on its review of DNSP provided information, Energeia assessed CP-PAL's in-scope AMI communications costs as meeting the Incurred test.

6.2.2.4 Technology Acceptance

The AER in its Draft Determination found that CP-PAL's proposed technology acceptance expenditure was already recovered under IT capex and it was therefore more likely than not that the proposed expenditure would not be incurred.[27]

[23] See pages 81 of the Draft Determination
[24] See pages 53 of the PAL Draft Determination Response
[25] See pages 81 of the Draft Determination
[26] See pages 53 of the PAL Draft Determination Response
[27] See pages 81 of the Draft Determination

CP-PAL argued that the expenditure was related to the cost of testing AMI technology, had not already been included in IT capex, and was therefore likely to be incurred. CP-PAL noted that AMI technology acceptance testing was complimentary but additional to IT acceptance testing.[28]

Energeia's review considered the nature of CP-PAL's AMI technology acceptance testing, their supporting information, and the potential consequences of not incurring the expenditure. Energeia's review found that the proposed expenditure was not recovered under IT capex, and that not incurring the expenditure was likely to result in a significantly increased risk of system failure.

Based on its review of DNSP provided information, Energeia assessed CP-PAL's AMI technology acceptance costs as meeting the Incurred test.

6.3 Commercial Standard

The following DNSP costs were assessed against the Commercial Standard test set forth in the revised OIC.

6.3.1 SP AusNet

6.3.1.1 Meter Supply Capex

The AER in its Draft Determination found that SP AusNet's proposed meter capital expenditure was based on unit prices more than double that of a comparable business, Powercor, and therefore involved a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.[29]

SP AusNet submitted revised meter unit prices for its WiMax and G3 meters based on current and indicative pricing, respectively. In the case of a single phase, single element, direct connected meter, the price differential has come down slightly to [C-I-C]% higher than Powercor in the best case of WiMax.[30]

Given the substantial variation in costs relative to the original business case, Energeia would have expected SP AusNet's governance process to have triggered a formal re-evaluation of the investment decision. Energeia's review of SP AusNet's supporting documentation has found that no in-depth re-evaluation appears to have occurred. [C-I-C][31]

Energeia's assessment of SP AusNet's proposed expenditure recognises the importance of not considering the cost of the meter hardware in isolation of the rest of the interrelated solution. Energeia therefore also considered whether the higher metering capex could be justified by a reasonable commercial business on the basis of savings elsewhere, particularly in IT and network expenditure. Finally, Energeia considered whether the Powercor comparison was relevant, i.e. whether moving to this solution would be feasible for SP AusNet.

Energeia originally supported SP AusNet's decision to deploy a WiMax solution on the basis of their own internal, Board approved commercial assessment of the option relative to mesh, which had shown that it was marginally cheaper. This was based on the view at the time that WiMax would retrieve the data faster, reducing the performance requirements of the IT system. Fewer network assets in the field meant that it should be less expensive to operate, and the use of an open standards based solution should make it cheaper to maintain by being able to source equipment and services from a wider range of suppliers.

[28] See pages 5 of the PAL Draft Determination Response
[29] See pages 79-80 of the Draft Determination
[30] See pages 46-49 of JAM's Draft Determination Response
[31] See Page 54 of SP AusNet's [C-I-C]

As shown in Figure 3, SP AusNet's cumulative expenditure on AMI per customer on key components is significantly higher than Powercor's, suggesting that its approach has not resulted in a significant savings in IT or network expenditure due to their decision to use a WiMax + G3 network solution. This analysis shows SP AusNet's projected cumulative per customer expenditure over the period to be [C-I-C]% higher than Powercor's. Energeia recognises that the difference is partially explained by cost sharing among the other businesses and SP AusNet's relatively large network area. However, these savings mainly accrue in the program management, tendering and solution development areas, and in Energeia's view, are unlikely to account for the substantial difference.

[C-I-C]

Figure 3 – DNSP Per Customer Cumulative Expenditure by Category to 2015

In order to better assess the two network options, Energeia also examined whether SP AusNet's proposed investment in the relatively costly WiMax + G3 network solution resulted in a lower network operating expenditure over the investment timeframe. Energeia found SP AusNet's proposed network and IT opex in 2015 to be [C-I-C]% higher than Powercor's, a significant premium. Other things being equal, a commercial business would not pay more for a solution that did not result in an offsetting reduction in operational costs.

[C-I-C]

Figure 4 – Powercor and SP AusNet IT and Network Opex in 2015

In Energeia's view, the relevance of this comparison relies on SP AusNet's ability to adopt Powercor's solution at this relatively late stage. Energeia therefore considered the cost and timing impacts to SP AusNet's program at a high level. The main costs involved include re-tendering for network equipment and meter modules, the cost of unwinding its current contracts, the cost of purchasing and integrating the mesh solution, and the cost of retrofitting the communications modules to the meters already installed.

Energeia's understanding of SP AusNet's metering solution is that they have used meters that allow for retrofitting of network cards at relatively low cost. This will require additional meter integration development and testing, but the field work should be relatively straightforward. The tendering costs will be a relatively minor cost, and the network and module costs are expected to be significantly cheaper, particularly if purchased to the same specification as those already deployed in Victoria.

Although SP AusNet would face additional IT, program and installation costs, Energeia is of the view that moving to a proven mesh solution may be the prudent option, even at this late stage. The basis for our view is the relative performance to date of the two options, and the significant remaining risks involved in persevering with what now appears to be a relatively high-risk WiMax strategy.

There is also likely to be a timeframe impact, and SP AusNet would be unlikely to meet its target. However, given SP AusNet's challenges to date, Energeia notes the uncertainty surrounding SP AusNet's achievement of the 2013 target under its own approach.

It should be noted that a similar issue arose in California, where Pacific Gas & Electric's (PG&E) rollout was halted after it began so that it could be relaunched using better communications technology. PG&E moved from Power Line Carrier based communications to Silver Springs Network (SSN) based mesh. Energeia also notes that anecdotal reports say that SSN's mesh technology is performing well for PG&E, and is believed to be outperforming the Itron solution being deployed by Southern California Edison.

Based on its review of DNSP provided information, and analysis of the relative costs and risks involved, Energeia assessed SP AusNet's meter capex costs as not meeting the Commercial Standard test.

6.3.1.2 Information Technology Opex

The AER in its Draft Determination found that SP AusNet's proposed IT opex was substantially more than comparable DNSPs, and therefore involved a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.[32]

SP AusNet argued that its IT opex costs were justified due to the relative immaturity of the solution, and the need for 24/7 support to meet their obligations. They also referenced a number of support and maintenance benchmarks from independent IT experts Gartner in support of their proposed expenditure.[33]

Energeia's assessment considered SP AusNet's proposal relative to the other DNSPs in 2015, SP AusNet's specific circumstances, and their support and explanation for the overall level of expenditure. 2015 was used as the benchmark year as it should only represent BaU related costs. Energeias' assessment does not include the original NMS expenditure, which SP AusNet has moved under network opex in its amended budget template.

Energeia assessment has found that SP AusNet's proposed IT operational expenditure is substantially higher than its peer networks in Victoria. A closer examination of the expenditure categories reveals this is mainly due to the substantially greater costs proposed for IT infrastructure support, as shown in Figure 5. Energeia

[32] See pages 107-108 of the Draft Determination

[33] See pages 69-70 of SP AusNet's Draft Determination Response

notes that SP AusNet's costs are likely to be higher than any of the other networks due to cost sharing of certain development and operational costs, but these are unlikely to account for the substantial difference.

[C-I-C]

Figure 5 – DNSP IT Infrastructure Opex in 2015

Energeia was unable to confirm whether SP AusNet's proposed IT operational expenditure met their suggested Gartner benchmarks as it was unclear how the benchmark should be applied to the data provided by SP AusNet. Energeia was also unable not reconcile the data provided by SP AusNet in Table 6.19 of their Draft Determination Response with its budget templates. Energeia's review of SP AusNet's supporting documentation did not identify any other explanation for SP AusNet's substantially higher level of proposed IT infrastructure expenditure.

Based on its review of DNSP provided documentation and supporting information, examples from other deployments, Energeia assessed SP AusNet's IT opex as partially meeting the Commercial Standard test.

6.3.1.3 Meter Data Management Opex

The AER in its Draft Determination found that SP AusNet's proposed meter data management opex was inconsistent with the required Victorian performance levels, and therefore involved a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.[34]

SP AusNet argued that its proposed meter data management opex costs met the commercial standard test, mainly due to the expected level of exceptions requiring manual intervention, and the cost of maintaining legacy systems and data.[35]

Energeia's assessment considered SP AusNet's proposal relative to the other DNSPs in 2015, SP AusNet's specific circumstances, the Victorian minimum functional specification, and SP AusNet's support for the overall level of expenditure. Energeia also considered the experience of Ausgrid, who has been managing over 400,000 interval data streams for over four years from its fleet of Manually Read Interval Meters (MRIM).

[34] See pages 109-111 of the Draft Determination
[35] See pages 46-47 of SP AusNet's Draft Determination Response

[C-I-C]

Figure 6 – DNSP Meter Data Management Opex in 2015

As shown in Figure 6, SP AusNet's proposed meter data management opex is consistent with its peer group on a per customer basis. SP AusNet proposed expenditure in 2015 is the second lowest, just behind Powercor. Energeia notes that results appear to be driven by economies of scale, with the larger networks of Powercor, SP AusNet, and to a less degree UED, outperforming the smaller networks of CitiPower and Jemena.

Energeia's discussion with Ausgrid and energy retailers regarding likely long-term interval data exception levels found that retailer validation rules and the impact of substitutions on customer calls to retailers largely drives demand for network's data management services. For example, customers are more likely to call about their bill when it has been generated using substituted data, which may occur up to 5% of the time.

Although Ausgrid continues to improve its data management processes each year by identifying new opportunities for automating exceptions, significant opportunities remain even after four years on from when the MRIM rollout was completed. Ongoing changes, such as the boom in meter replacements due to the demand for solar PV, continue to introduce new challenges and complexity into the system over time.

Based on its review of DNSP provided information and examples from other deployments, Energeia assessed SP AusNet's meter data management opex as meeting the Commercial Standard test.

6.3.1.4 Meter Maintenance Opex

The AER in its Draft Determination found that SP AusNet's proposed meter maintenance opex was substantially greater than the costs expected of a reasonable business, given the obligations in respect of the required test regime for meters under AS 1284 and Chapter 7 of the NER.[36]

SP AusNet argued that its proposed meter maintenance opex costs reflected the key tasks it considered necessary to meet its business and regulatory obligations in respect of the meter maintenance function. It provided further information in respect of costs and FTEs, as well as its Meter Asset Management Plan.[37]

[36] See pages 113 of the Draft Determination

[37] See pages 48-49 of SP AusNet's Draft Determination Response

Energeia's assessment considered SP AusNet's proposal relative to its statutory meter maintenance obligations, its costs in 2015 relative to other DNSPs, SP AusNet's specific circumstances, and its supporting information including its Meter Asset Management Plan.

[C-I-C]

Figure 7 – DNSP Meter Maintenance Opex in 2015

Energeia's assessment of SP AusNet's meter maintenance expenditure has found that is consistent with its relevant statutory obligations and is comparable by 2015 to its peer DNSPs on a per capita basis as shown in Figure 7. As with meter data management, these results indicate that customer numbers materially impact on the per customer cost of maintaining AMI meters.

Energeia notes that SP AusNet has included meter reading operational expenditure costs in its amended budget for 2014-15 related to redundancy payments for meter readers. As meter reading is an outsourced activity, and commercial meter reading contracts do not ordinarily include redundancy cost pass-through, Energeia has found that this expenditure does not meet the Commercial Standard test.

Based on its review of DNSP provided supporting information, and examples from other deployments, Energeia assessed SP AusNet's meter maintenance opex as meeting the Commercial Standard test.

Based on its review of DNSP provided supporting information, and examples from other deployments, Energeia assessed SP AusNet's meter reading opex as not meeting the Commercial Standard test.

6.3.1.5 Communications Infrastructure Maintenance Opex

The AER in its Draft Determination found that SP AusNet's proposed network maintenance opex was substantially greater than the prudent level of resourcing in the circumstances.[38]

SP AusNet argued that its proposed network maintenance opex was appropriate given Victoria's minimum performance level requirements. It provided further information in respect of its vendor support contracts, its meter to MMS support model, and associated costs and FTEs.[39]

[38] See pages 116 of the Draft Determination

[39] See pages 52-55 of SP AusNet's Draft Determination response

Energeia's assessment considered SP AusNet's proposal relative to its network performance obligations under Victoria's minimum performance level requirements, it's opex in 2015 relative to other DNSPs, it's specific circumstances as required under the revised OIC, and its additional support and explanation.

As previously discussed in Section 7.3.1.1, Energeia's review of SP AusNet's communications network opex has found that it is [C-I-C]% higher that of its closest comparator, Powercor. This assessment takes SP AusNet's inclusion of NMS costs into account by offsetting its proposed network maintenance costs by CP-PAL's combined NMS opex. Energeia has added the two company's costs together to take a conservative view on the potential cost savings from sharing a common service provider and solution.

Energeia's consideration of SP AusNet's substantially higher opex in 2015 has found that it is not attributable to the company's specific circumstances other than its decision to adopt a WiMax / G3 network solution. The other DNSPs have the same performance level requirement as SP AusNet, and in the case of Powercor, a similar number of customers and network territory, yet expect to incur one quarter of the cost proposed by SP AusNet in 2015. Energeia therefore finds SP AusNet's proposed expenditure does not meet the Commercial Standard test.

Based on its review of DNSP provided documentation and supporting information, examples from other deployments, Energeia assessed SP AusNet's communications infrastructure maintenance opex as not meeting the Commercial Standard test.

6.3.1.6 Project Management Opex

The AER in its Draft Determination found that SP AusNet's proposed project management opex was substantially greater than the prudent level of resourcing in the circumstances. Specifically, the PMO cost forecasts for 2012 and 2013 did not reflect the PMO resourcing of a mature program in its late execution phase.[40]

SP AusNet argued that its proposed project management opex was appropriate given the scope of work planned over the budget period. It provided further information in respect of its forecast resourcing levels and associated costs in the form of four pages of roles and responsibilities in bullet point format. Energeia notes that it could not reconcile SP AusNet's project management costs in its response to its amended budget.[41]

Energeia's assessment of SP AusNet's proposal focused on its resourcing levels and cost per FTE, it's specific circumstances as required under the revised OIC, and the additional support and explanation it provided. Energeia notes that SP AusNet's project management opex appears to reflect management costs that other businesses have incorporated into their service line costs.

Energeia's initial review found that SP AusNet's support for its project management expenditure was insufficient for determining whether it met the Commercial Standard test. Energeia therefore requested additional information to support its planned expenditure. Specifically, SP AusNet was requested to provide its organisational structure and roles in 2015 for providing the Regulated Services.

SP AusNet did not provide the requested information. Energeia would have expected an AMI organisational structure, operating model, divisional and branch business plans, and key position descriptions to have been made available if these were the basis for SP AusNet's planned expenditure.

In the absence of receiving appropriate business planning artefacts, Energeia's has had to assume that SP AusNet's proposed expenditure does not reflect the level of planning that a reasonable commercial business would have developed in the circumstances.

[40] See pages 118 of the Draft Determination
[41] See pages 65 of SP AusNet's Draft Determination response

Nevertheless, Energeia believes the overall level of resourcing in the PMO appears to be reasonable on the basis of the program being behind schedule and peer resourcing levels. The costs for the AMI PMO solution, sourcing and solution FTEs in 2012, at [C-I-C]% to [C-I-C]% of market rates, are excessive.

Energeia recognises that SP AusNet's PMO costs related to program governance, tendering, regulation and quality assurance would increase if it were to adopt a mesh communications solution.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed SP AusNet's PMO opex as not meeting the Commercial Standard test.

6.3.2 UED and Jemena

6.3.2.1 Installation Capex

The AER in its Draft Determination found that the assumptions underpinning JEN and UED's proposed installation capital expenditure could not be supported. These assumptions included a [C-I-C] incidence rate of panel replacements and truck visit costs above previously determined rates for similar services classified as alternative control services.[42]

JEN and UED argued via their service provider JAM that passing over complex sites was an efficient deployment practice, and that the expenditure was competitively tendered as part of the installation contract and must therefore be accepted as prudent under the revised OIC.[43] JAM also noted that skipping over panel replacement sites did not incur an additional revisit fee.[44]

In support of their claim, JEN and UED provided a report by KEMA that reviewed the expenditure against the Commercial Standard test. KEMA's report found that the expenditure met the Commercial Standard test.[45]

In their consideration of the test, KEMA claimed that the approach taken when encountering panel replacements was best practice among utilities in order to effectively divide work between job categories. This allowed each job category to be serviced by an appropriately trained and skilled workforce.

KEMA further noted that the [C-I-C] figure cited applied to about half of the total population, meaning that the overall average number was around [C-I-C], and very close to the number accepted by the AER for other DNSPs. They also note that since the Victorian government opened their review, the actual rate of refused access has exceeded 20%, which may add unanticipated costs.

Energeia's review of JEN and UED's in-scope installation capex has considered their response to the Draft Determination, the report by their technical consultants, and the Ausgrid pilot of 10,000 AMI meters and rollout of interval meters to over 125,000 sites.

Energeia agrees that the adopted approach is an industry standard practice. It is similar to the approach that Ausgrid took when deploying its 10,000 pilot of AMI meters on a door-to-door basis, which was designed to test installation costs and practices.

Under 5C.3 of the revised OIC, expenditure is prudent and must be approved where it is a contract cost, unless it is established that the contract was not let in accordance with a competitive tender. Energeia's review of these costs has found that as they form part of the competitively tendered contract for meter installation, they must be approved under the revised OIC.

[42] See pages 143-144 of the Draft Determination
[43] See pages 50-52 of JAM's Draft Determination response
[44] See page 56 of JAM's Draft Determination response
[45] See page 23 of the KEMA report

Based on its review of DNSP provided information, and consideration of good industry practice, Energeia assessed JEN and UED's in-scope installation capex costs as meeting the Commercial Standard test.

6.3.2.2 New Connections Adds and Alts Capex

The AER in its Draft Determination found that JEN and UED's proposed new connections, adds and alts expenditure did not meet the Commercial Standard test. This was due to the forecast number of meters required, the assumed percentage of antennas required and the inclusion of out-of-scope installation costs[46]

JEN and UED accepted via their service provider JAM that the original meter expenditure was overstated and modified it accordingly.[47] JAM argued that [C-I-C] was appropriate up to 2012 due to the lack of density up to that point and the relative costs of a truck visit where it was later found to be necessary. JAM modified its antenna assumptions to be [C-I-C] in mass rollout areas and [C-I-C] in new developments from 2013. [48]

In support of their claim, JEN and UED provided a report by KEMA that reviewed the expenditure against the Commercial Standard test. KEMA's report found that the expenditure met the Commercial Standard test.[49]

Energeia notes that the focus of KEMA's report focused on the potential impact of the AER's Draft Determination on the antenna allowance for all sites during the meter rollout. It did not address the AER's finding that expenditure on antennas for [C-I-C] of new connection, alts and add sites did not meet the Commercial Standard test.

Energeia's review of JEN and UED's in-scope expenditure for new connections, adds and alts focused on the antenna assumption for new connections, alt and adds only. Energeia has specifically considered JAM's claims that a [C-I-C] assumption for new connections during 2012 is required due to uncertainty regarding the density of the local mesh, and the economics of responding with a truck visit if expenditure is disallowed.

JEN and UED's networks are largely suburban in nature, meaning that most new connections in JEN and UED's network areas are likely to be driven by infill and redevelopment. Energeia expects that multi-drop arrangements will be used in medium to high density sites, which allows large numbers of meters to be networked using cables and to share a single communications link. This should bring down the average number of antennas required per meter significantly.

Energeia's view is that the assumption for new connections post rollout in 2014 and 2015 should be no higher than the average experienced to date, which is around [C-I-C]. This is believed to represent a conservative assumption given the expected preponderance of knock-down rebuilds and medium to high density developments in the JEN and UED network areas.

Based on its review of DNSP provided information, and consideration of their specific circumstances, Energeia assessed JEN and UED's in-scope new connections, alts and adds capex costs as not meeting the Commercial Standard test.

6.3.2.3 AMI Technology and Communications

The AER in its Draft Determination found that JEN and UED's proposed AMI technology and communications expenditure did not meet the Commercial Standard test. This was due to the AER's view that the proposed

[46] See pages 143-144 of the Draft Determination
[47] See page 62 of JAM's Draft Determination response
[48] See page 65 of JAM's Draft Determination response
[49] See page 23 of the KEMA report

expenditure was more reflective of an initial set-up phase, and not a late stage rollout. The AER reduced JEN and UED's proposed expenditure related to network augmentation and the testing lab.[50]

JEN and UED argued via their service provider JAM that the testing lab was required to undertake the anticipated AMI testing over the period.[51] JAM stated that the expenditure reflected reduced testing activity, and only included a 'skeleton crew' of 3 FTEs, down from 8 FTEs during the program's peak.

In support of their claim, JEN and UED provided a report by KEMA that reviewed the expenditure against the Commercial Standard test. KEMA's report found that the expenditure met the Commercial Standard test.[52]

KEMA's consideration focused on the important role played by the Quality Assurance (QA) function during an AMI deployment and ultimately BaU. The QA process rejected at least two major software releases from being deployed that were found to be defective. Furthermore, QA continued to have an important BaU role due to the expectation of ongoing system and hardware changes, and need to develop and deploy the HAN. They also noted that they were unaware of commercial facilities for testing of this type.[53]

Energeia requested further information regarding the businesses' practices with respect to managing changes to remotely read electronic meters prior to the AIMRO program in 2008. The purpose of this request was to identify the key differences between then and 2015 that justified the proposed expenditure.

Remotely read electronic meters at this time were typically read using cellular communication networks. These meters and communication devices were integrated across the remote metering reading, meter data management, market interfacing, billing and connection point management systems. Managing these assets, which included interval data, firmware, a communications network and a daisy chain of integrated IT systems, required the DNSP to manage technology change in a controlled fashion back in 2008.

UED and JEN responded that the meter specification in 2008 required meters to be compatible with the meter reading system, Itron's MVRS and MV90 software products. This compatibility was independently certified by Itron, who effectively took on the responsibility for testing the meter, at least up to the point of reading and validating the data in the meter. The DNSP's testing was therefore limited to ensuring that the data flowed from the meter to the bill, which took only a handful of hours from the testing team.[54]

According to UED and JEN, there have only been [C-I-C] field based firmware upgrades or patches to small populations of meters since electronic meters and remote communications were introduced into their asset fleet. Under this scenario, the meter vendors were required to have their meters independently tested by Itron to ensure that they would function correctly within the remote meter reading software system.

Energeia's assessment considered the ongoing need for testing, the experience of other major AMI and smart meter deployments, the alternatives to having an in-house lab, and whether UED and JEN's approach to addressing the perceived need was reasonably commercial.

Energeia sees a significant need for ongoing testing of the end-to-end AMI system post deployment based on the ongoing level of complex technology change. Key drivers of this change include developing and testing HAN functionality and managing ongoing updates to network and meter hardware and related software. Energeia expects the level of activity will be significantly less than observed during the peak of the AMI program, and it is therefore appropriate that the number of FTEs is reduced by over half by 2014.

Energeia also agrees with KEMA that an end-to-end test facility is important given the complexity of the AMI solution. The QA environment is a form of insurance against the implementation of a software or firmware

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50 See pages 143-144 of the Draft Determination

51 See page 69-73 of JAM's Draft Determination response

52 See page 23 of the KEMA report

53 See page 17 of the KEMA report

54 See page 16 of Attachment 2 of JEN's response to Energeia's questions

upgrade that could potentially lead to a major system interruption. Although the pace of software and firmware changes are expected to decrease over time, Energeia notes that other metering deployments, such as Ausgrid's, continue to rely on a purpose built testing lab years after the rollout ended.

Longer-term, Energeia expects testing to become lower cost as test engineers automate the testing process, but does not expect to see a return to a system similar to that seen in 2008. This is mainly because of the integrated nature of AMI, whose data feed reaches across the enterprise. While the upstream NMS, MMS and MDM software vendors could certify a given meter upgrade as being compatible with their system, they would not be able to verify the impact of any changes on the rest of the integrated, upstream IT systems.

Based on its review of DNSP provided information, *examples from other deployments, and the unavailability of a commercial alternative, Energeia assessed JEN and UED's quality assurance costs as meeting the Commercial Standard test.*

6.3.2.4 IT Infrastructure and Systems Capex

The AER in its Draft Determination found that JEN and UED's proposed IT infrastructure and systems capital expenditure did not meet the Commercial Standard test. This was due to the forecast level of hardware replacement in 2015, which assumed the need to replace all five, six-year-old redundant systems at the same time. The AER reduced expenditure on hardware and systems in 2015.[55]

JEN and UED argued via their service provider JAM that their documented policy and plans represented good industry practice and therefore met the Commercial Standard test. In support of this claim, JAM produced a number of statements from key software partners including Oracle, Hitachi and independent industry analysts supporting the view that 4-5 years was a reasonable replacement timeframe for IT assets. JAM also claimed that a staggered, piecemeal replacement approach was not possible due to the need to keep the systems in sync, particularly for disaster recovery purposes.[56]

In support of their claim, JEN and UED provided a report by KEMA that reviewed the expenditure against the Commercial Standard test. KEMA's report found that the expenditure met the Commercial Standard test.[57]

In its review of the expenditure against the Commercial Standard test, KEMA identified that the lifecycle of an IT asset begins before it is commissioned due to the need to integrate, test and install the system. This typically adds 6 to 18 months to the lead time required for purchasing new IT assets. They also identified that JAM's IT asset replacement guidelines allow for a [C-I-C] year replacement cycle, depending on the asset.

Energeia does not agree with KEMA that IT assets would normally be purchased up to 18 months prior to implementation due to the time required for integration, testing and installation. In Energeia's view, 6 to 9 months is a more reasonable timeframe, given the high cost of extended IT programs. However, the difference is immaterial.

Energeia's review of JEN and UED's proposed IT infrastructure expenditure considered the need for replacement, the DNSP's response to this need, and the relevant industry standard, where available. Energeia believes that JAM has established that the age of the IT assets installed in 2010 will be between 6 years in 2015, and that replacing fully redundant systems will require coincident replacement of key systems.

In Energeia's view, JAM has substantiated that its planned two year replacement program commencing in 2015 is consistent with a reasonable commercial business in the circumstances, and the need to purchase the equipment in advance of the replacement date, which may be up to nine months later.

[55] See pages 143-144 of the Draft Determination

[56] See pages 74 to 79 of JAM's Draft Determination response

[57] See page 23 of the KEMA report

Based on its review of DNSP provided information, Energeia assessed JEN and UED's in-scope IT Infrastructure and System Costs as meeting the Commercial Standard test.

6.3.2.5 IT Capex – 'Second Meter Supplier'

The AER in its Draft Determination found that UED's proposed IT capital expenditure to integrate a second meter supplier did not meet the Commercial Standard test. The AER reduced the expenditure to reflect a relatively minor IT configuration change in order to integrate the additional metering supplier.[58] This expenditure relates to UED only, JEN did not propose it in their amended budget application.

UED argued in its response to the Draft Determination and subsequent correspondence with the AER that the expenditure met the Commercial Standard test because the use of two meter suppliers was standard industry practice to guard against price and supply risks. The costs were high due to the complexity involved in integrating and testing a second meter supplier.[59]

In support of their claim, UED provided a report by KEMA that reviewed the expenditure against the Commercial Standard test. KEMA's report found that the expenditure met the Commercial Standard test.[60]

KEMA stated in its report that adding a new supplier would be non-trivial because of the impact on asset and configuration management, and the need to adapt each software and hardware system to make it compatible with the new meter supplier. KEMA did not justify the commercial need for the expenditure other than to say it was 'good industry practice to mitigate monopoly pricing by suppliers and to keep available a secondary supply should the primary supplier demonstrate price, delivery, or quality issues.'[61]

Energeia's assessment focused on evaluating the proposed expenditure relative to its perceived benefits. This is in our view the commercial standard that a reasonable business would exercise in the circumstances. UED's specific circumstances were also taken into consideration, as required under the revised OIC.

Energeia agrees with UED and KEMA that having multiple meter suppliers is standard industry practice and helps guard against price and supply risk. However, recouping the proposed [C-I-C] million expenditure would require UED to save over [C-I-C] off its annual [C-I-C] metering capex budget for over 20 years, an unlikely outcome. Supplier performance risk is also an issue, but this can be mitigated at far lower cost through inventory management practices and the credible threat of replacement for non-performance.

Based on its review of DNSP provided information, and analysis of the costs relative to the benefits, Energeia assessed UED's second meter supplier capex as not meeting the Commercial Standard test.

6.3.2.6 Asset Strategy and Planning Capex

The AER in its Draft Determination found that JEN and UED's proposed AMI asset strategy and planning capital expenditure did not meet the Commercial Standard test. This was based on the forecast number of FTEs relative to the expected level of activity required under BaU.[62]

JEN and UED argued via their service provider JAM that the FTEs were necessary due to the impact of AMI on asset strategy and planning. In particular, AMI includes a communications network that introduces

[58] See pages 126 of the Draft Determination
[59] See page 87-93 of JAM's Draft Determination response
[60] See page 23 of the KEMA report
[61] See page 26 of the KEMA report
[62] See pages 150-152 of the Draft Determination

additional asset tasks and expertise to manage security, meter communications, network development, network assets, and network management software.[63]

In support of their claim, JEN and UED provided a report written by Deloitte, which found that the expenditure met the Commercial Standard test. They noted that, according to their modelling and research, JAM had underestimated its FTE requirements.[64]

The basis of Deloitte's conclusion was a bottom up analysis developed through discussions with JAM personnel and review of selected international AMI deployments. The model focused on the resourcing requirement for field investigations of meter, communications and network related faults and issues. These were for the most part built up using historical data, and cross checked with overseas data.

Energeia's assessment focused on identifying the key impacts of AMI on the businesses' asset strategy and planning functions, and assessing whether the proposed response was reasonably commercial. As the stakeholder relations and QA services have already been considered elsewhere, Energeia's review here is limited to the need for additional FTEs in metering, communications and security.[65]

Energeia contacted Ausgrid and PG&E to validate the assumptions used around meter and communications faults. These discussions confirmed the assumptions used in the Deloitte model in most cases. Energeia found that the meter and communications related faults are likely to be higher than the number assumed in the Deloitte model, at least for the first few years due to an extended period of 'infant mortality'.

The key assumption that Energeia was unable to corroborate is the assumed level of customer investigations to 2015. Current levels of customer investigations are in part due customers becoming used to the technology, something that Energeia expects will largely fall away over time. This assumption drives the need for 2 of the 5 field based FTEs supporting JEN and UED's local area network in 2015. Energeia expects customer investigations to fall over time with experience, but the timing remains uncertain.

Energeia's review of the expenditure for additional metering, communications and security resources has found that these are generally supported by the material change in AMI's functional scope. In particular, AMI includes a step change in telecommunication and security functionality and risk that did not previously exist.

Based on its review of DNSP provided information, and expected changes in customer behaviour over time, Energeia assessed JEN and UED's asset strategy and planning capex as meeting the Commercial Standard test.

6.3.3 CitiPower and Powercor

6.3.3.1 Meter Supply – 'Other Costs'

The AER in its Draft Determination found that CP-PAL's proposed other costs under AMI meter supply expenditure did not meet the Commercial Standard test. This was based on the forecast number of FTEs relative to the expected level of resourcing required for contractor management and logistics.[66]

CP-PAL argued that the proposed expenditure was appropriate to manage a field deployment of this kind, and that it also included BaU metering provision costs. In support of its proposal, CP-PAL provided a detailed

[63] See page 87-93 of JAM's Draft Determination response
[64] See page 27-38 of the Deloitte report
[65] JEN-UED moved the AMI communications field expenditure under AMI network operations in their amended budgets.
[66] See page 169 of the Draft Determination

expenditure model, which included role descriptions for field deployment, role costs and resourcing levels. No descriptions were provided for management, solution development, assurance or asset management roles.[67]

Energeia's review considered CP-PAL's level of expenditure relative to its peers, the job descriptions provided for each FTE, the key assumptions underpinning its cost estimates, and the specific circumstances of CP-PAL as required under the revised OIC. Energeia looked at CP-PAL's costs in 2012-13 during the rollout separately from its costs in 2015 under BaU.

CP-PAL's total expenditure per customer on meter supply costs for 2012-13 in their amended budget is the lowest in Victoria. Energeia notes that this analysis is based on total costs, which includes contract costs, but this was the only analysis possible given reporting differences among the businesses. The costs may also reflect differences in the timing of each company's rollout, which Energeia believes are marginal.

Energeia's high level review of CP-PAL's detailed cost model has found that it is consistent with that of a reasonable commercial business in the circumstances.

CP-PAL's total expenditure per customer on meter supply costs for 2015 in their amended budget is the highest in Victoria. Energeia notes that this analysis is based on total costs, which include contract costs, but this was the only analysis possible given reporting differences among the businesses.

Energeia's review of CP-PAL's proposed BaU meter supply expenditure has found that it is [C-I-C] higher on average than UED and JEN in 2015. Energeia has excluded SP AusNet's meter costs from the assessment due to uncommercial nature of the expenditure. As the rollout will have finished by this time, CP-PAL's relatively higher meter supply costs cannot be not due to differences in program timing, nor are they likely to be due to differences in metering costs. Energeia has checked CP-PAL implied failure rates and does not believe these are driving the substantially higher costs per customer.

Based on the unexplained, substantial variation from the BaU meter costs of peer networks, Energeia finds PC-CP's proposed BaU meter supply costs in 2015 to represent a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances. Nominally, they should be about the same as UED and JEN, who are deploying the same type of meter and local area network.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's in-scope meter supply costs in 2012-13 as meeting the Commercial Standard test.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's in-scope meter supply costs in 2015 as not meeting the Commercial Standard test.

6.3.3.2 Meter Installation capex – 'Other Costs'

The AER in its Draft Determination found that CP-PAL's proposed other costs under AMI meter installation capex did not meet the Commercial Standard test. This was based on the level of forecast expenditure relative to expected contractor management and support costs during the rollout, and under BaU.[68]

CP-PAL revised its amended budget to remove BaU costs related to customer alts and adds recovered under ACS. CP-PAL argued that the proposed expenditure was appropriate to manage a field deployment of this kind, and did not include any customer service costs related to managing meter or communications faults, as these were recovered under customer service costs.[69]

[67] See page 69-71 of the Powercor Draft Determination response

[68] See pages 150-152 of the Draft Determination

[69] See page 74 of the Powercor Draft Determination response

In support of their claim, CP-PAL provided a report written by Deloitte, which found that the expenditure met the Commercial Standard test. Energeia notes that the report focused on validating FTEs related to the rollout, and did not address BaU costs. According to the Deloitte report, no meter installation FTEs they assessed were required in 2015.[70]

Energeia's review considered CP-PAL's level of expenditure relative to its peers during and after the meter rollout, the job descriptions provided for each FTE, the key assumptions underpinning its cost estimates, CP-PAL's meter replacement volume assumptions under BaU, and the specific circumstances of CP-PAL as required under the revised OIC. Energeia looked at CP-PAL's costs in 2012-13 during the rollout separately from its costs in 2015 under BaU.

CP-PAL's total expenditure per customer on meter installation costs for 2012-13 in their amended budget is the lowest in Victoria. Energeia notes that this analysis is based on total costs, which include the contract costs, but this was the only analysis possible given reporting differences among the businesses. The costs also reflect differences in the timing of each company's rollout, which Energeia believes are marginal.

As most of the rollout is planned and managed by the businesses, Energeia would expect a significant expenditure in this area. The use of external contractors, and the quality and safety risks involved in a program of this scale, justifies a significant expenditure on quality assurance and safety auditing. Finally, CP-PAL's expenditure includes expenditure on issue resolution, which Energeia also finds to be reasonable.

Energeia's high level review of its detailed cost model has found that it is consistent with that of a reasonable commercial business in the circumstances. Energeia agrees with CP-PAL's assumption of 2 months of metering stock in inventory due to the material cost impact of a supply shortage on the program. Energeia notes that the assumed 10% WACC is higher for the meter installation business than it would be for CP-PAL.

CP-PAL's total expenditure per customer on BaU meter installation costs in 2015 is the highest in Victoria. Energeia notes that this analysis is based on total costs, which include the contract costs, but this was the only analysis possible given reporting differences among the businesses.

Energeia's review of CP-PAL's proposed BaU metering installation expenditure has found that it is 800% higher on average than its peers. Energeia notes that CP-PAL's model assumes replacement numbers in 2015, which drive its assumption of meter installation costs over the period. No information was provided by CP-PAL in support of their assumed meter installation volumes in 2015. Energeia has checked CP-PAL's implied failure rates and does not believe these are driving the substantially higher costs per customer.

Based on the substantial variation from BaU meters costs of peer networks, and the lack of support for the assumed number of installations in 2015, Energeia finds PC-CP's proposed BaU meter installation costs in 2015 represent a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's in-scope meter installation capex in 2012-13 as meeting the Commercial Standard test.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's in-scope meter installation capex in 2015 as not meeting the Commercial Standard test.

[70] See pages 29-36 of the Deloitte report

6.3.3.3 Communication Equipment Supply – 'Other Costs'

The AER in its Draft Determination found that PowerCor's proposed 'other costs' for AMI communications capex did not meet the Commercial Standard test. This was based on the unexplained, substantially higher level of forecast expenditure relative to CitiPower.[71]

Powercor argued in its response that the proposed expenditure related to the purchase of communications equipment for customers where they could not be cost effectively reached by the mesh network. CitiPower's network is relatively compact, and therefore did not require the same level of expenditure on 3G, PSTN and satellite communications equipment.[72]

Energeia's review considered the nature of Powercor's expenditure, the assumptions driving its expenditure forecast, and its specific circumstances as required under the revised OIC.

Energeia's high level review of CP-PAL's proposed in-scope communication equipment supply expenditure has found it accords with the Commercial Standard test. This is based on 3G, PSTN and satellite equipment purchase assumptions being consistent with the expected mesh network solution coverage. Equipment prices are consistent with market rates, though Energeia notes PSTN costs are more than double 3G rates.

Based on its high level review of DNSP provided information, Energeia assessed Powercor's in-scope communications equipment supply costs as meeting the Commercial Standard test.

6.3.3.4 Communication Equipment Installation – 'Other Costs'

The AER in its Draft Determination found that CP-PAL's proposed 'other costs' for AMI communications installation capex did not meet the Commercial Standard test.[73]

CP-PAL argued in its response that the proposed expenditure related to the cost of designing, planning and installing its AMI communications network. In support of its proposal, CP-PAL provided a detailed expenditure model, which included role descriptions for field deployment, role costs and resourcing levels.[74]

Energeia's review considered the nature of CP-PAL's expenditure, the level of resourcing and the cost of resources included in its cost modelling, its overall network costs relative to peer networks, and CP-PAL's specific circumstances as required under the revised OIC.

CP-PAL's in-scope expenditure includes communications design, development and deployment management. Energeia reviewed the FTE's included in the cost build-up, and is generally satisfied that they reflect a reasonable level of resourcing and resource costs for the AMI project.

Energeia also considered CP-PAL's total capital expenditure on its mesh communications network against that of UED and JEN, who are deploying the same solution, albeit across suburban rather than urban or rural networks. Although they are buying the same equipment, JEN and UED's overall cost includes contracted installation rates, so the comparison is a rough market test of CP-PAL's overall installation costs.

According to Energeia's modelling, Powercor's communications network costs are [C-I-C] higher than UED and JEN's costs, but CitiPower's are [C-I-C] lower. CP-PAL's combined network costs are [C-I-C] lower than UED and JEN's costs on a simple average basis. Given the cost of the equipment is the same, UED and JEN's installation costs are based on a competitively tendered contract, and CP-PAL's urban and rural

[71] See pages 172-173 of the Draft Determination
[72] See page 80 of the Powercor Draft Determination response
[73] See pages 175 of the Draft Determination
[74] See page 86 of the Powercor Draft Determination response

networks are likely to be higher cost to serve, Energeia finds CP-PAL's installation costs as being reasonable.

Based on the foregoing bottom up and top down assessment, Energeia's review of CP-PAL's in-scope installation costs has found them to meet the Commercial Standard test.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's in-scope communications installation costs as meeting the Commercial Standard test.

6.3.3.5 IT Capital Expenditure

The AER in its Draft Determination found that PC-CP's proposed IT capex did not meet the Commercial Standard test. The AER specifically rejected CP-PAL's proposed IT capex for workforce scheduling, performance and regulatory reporting, program management and IT infrastructure.[75]

CP-PAL accepted the AER's view regarding a portion of its workforce scheduling expenditure, but reclassified most of it under connection point management. CP-PAL argued in its response that the disputed expenditure related to necessary investments in a data warehouse and IT infrastructure to address key IT gaps, which together justified the proposed IT program management expenditure.[76]

In support of their claim regarding IT infrastructure capex, CP-PAL provided a report written by Deloitte, which found that the expenditure met the Commercial Standard test. Energeia notes that Deloitte's IT infrastructure cost analysis found a 2% increase over CP-PAL's submission.[77]

Energeia's review considered the nature of CP-PAL's expenditure, their costs relative to peer networks, their supporting information, and their specific circumstances as required under the revised OIC.

Energeia's review of the connection point projects found they were developed to address identified gaps in the program to date. The need and commercial basis for the investment was relatively well supported given the stage of the project's development. Energeia's view is that rejecting this expenditure is likely to increase overall program costs, a reasonable commercial business would therefore incur them.

Energeia's review of CP-PAL's information supporting its investment in the database warehouse for regulatory and performance reporting has found it to be mislabelled. According to CP-PAL's own documentation, the project is meant to address limitations in the legacy MDS system, which is mainly used to support tariff analysis and development. It should therefore be considered a revenue management related investment, and is in Energeia's view an in-scope investment.

According to Energeia's modelling, CP-PAL's total revenue management investment including its data warehouse project is roughly [C-I-C] lower than JEN and UED's level of investment. Energeia has considered the potential impact of solution design and development cost sharing on the result, and believes this should be comparable between CP-PAL and JEN-UED.

Energeia compared CP-PAL's overall IT infrastructure capex with that of UED and JEN, which are supporting a similar number of systems of a similar age, and to an identical standard. Energeia's modelling found CP-PAL's level of investment to be [C-I-C] lower than UED and JEN on a combined basis. Energeia has therefore found CP-PAL's proposed investment in IT infrastructure to be reasonable.

[75] See pages 177-180 of the Draft Determination
[76] See page 86 of the Powercor Draft Determination response
[77] See page 29-36 of the Deloitte report

Energeia notes that the reasonableness of CP-PAL's proposed IT infrastructure capex is supported by the modelling work performed by their consultant, and the additional information provided in their response document. Specifically, the businesses estimate that they will be storing 300TB of data across 5 duplicate systems by 2015. Energeia has relied on the view of their consultant that five duplicate systems is reasonable.[78]

Based largely on the finding that the proposed level of IT infrastructure capex is reasonable, Energeia also finds the proposed level of IT program management capex to be reasonable. This is based on industry standard benchmarks of 10% for IT program management costs, which is around twice the level being proposed by CP-PAL in light of the relatively lower risks involved at this stage of the program.

Based on its review of DNSP provided information and examples from other deployments, Energeia assessed CP-PAL's in-scope IT capex as meeting the Commercial Standard test.

6.3.3.6 Meter Data Services

The AER in its Draft Determination found that PC-CP's proposed opex for meter data services did not meet the Commercial Standard test. CP-PAL's resourcing levels implied a higher manual handling rate than was reasonable given the required performance levels.[79]

CP-PAL submitted an amended expenditure estimate, which was slightly higher than its original budget. CP-PAL argued that the revised expenditure met the Commercial Standard test as it reflected a bottom up analysis of the activity required to deliver the service using actual error rates.[80]

In support of their claim regarding meter data services opex, CP-PAL provided a report written by Deloitte, which found that the expenditure met the Commercial Standard test. Energeia notes that Deloitte's meter data services cost analysis found an 11% increase over CP-PAL's submission, due to higher than previously estimated resourcing costs.[81]

Energeia's review considered the nature of CP-PAL's expenditure, their resourcing levels and costs, their expenditure relative to peer networks, their supporting information, and their specific circumstances as required under the revised OIC. Energeia also requested further information from CP-PAL regarding any root cause analysis undertaken in support of its long-term error rate assumptions.

Deloitte confirmed that no formal root cause analysis was undertaken as part of its cost modelling. Current exception rates were analysed to form a view on the potential scope for these rates to change over time in response to additional capital investment, particularly IT. Energeia accepts this as a reasonable approach.

Energeia's consideration of DNSP's meter data service expenditure levels was outlined in Section 7.3.1.3. In addition, Energeia reviewed the bottom up modelling by Deloitte, including the underlying exception rate assumptions, and number and cost of FTEs. Energeia found CP-PAL's resourcing and resource costing to reasonable generally, except for the 1.5 FTEs to manage data processes for basic and MRIMs in 2014-15.

Based on its review of DNSP provided information and examples from other deployments, Energeia assessed CP-PAL's meter data opex as not meeting the Commercial Standard test.

[78] See page 38 of the Deloitte report
[79] See pages 177-180 of the Draft Determination
[80] See page 86 of the Powercor Draft Determination response
[81] See page 29-36 of the Deloitte report

6.3.3.7 Communication Operations

The AER in its Draft Determination found that PC-CP's proposed AMI communications opex did not meet the Commercial Standard test. CP-PAL's fault management resourcing levels were found to be unreasonable relative to the highly reliable performance of its mesh network. Its expenditure on quality assurance and data delivery was found to have already been recovered under the respective capex category.[82]

CP-PAL submitted an amended budget for its AMI technology and communication opex, which excluded QA costs it had reclassified as capex. CP-PAL argued that the revised expenditure met the Commercial Standard test as it matched a bottom up analysis of the activity required to deliver the services, and that these costs had not already been recovered elsewhere in its amended budget.[83]

In support of their proposed AMI communications opex, CP-PAL provided a report written by Deloitte, which found that the expenditure met the Commercial Standard test. Deloitte's finding was based on bottom up modelling of FTE requirements for the assumed level of activity and market sourced resourcing costs.[84]

Energeia's review considered the nature of CP-PAL's expenditure, their resourcing levels and costs, their costs relative to peer networks, their supporting information, and their specific circumstances as required under the revised OIC.

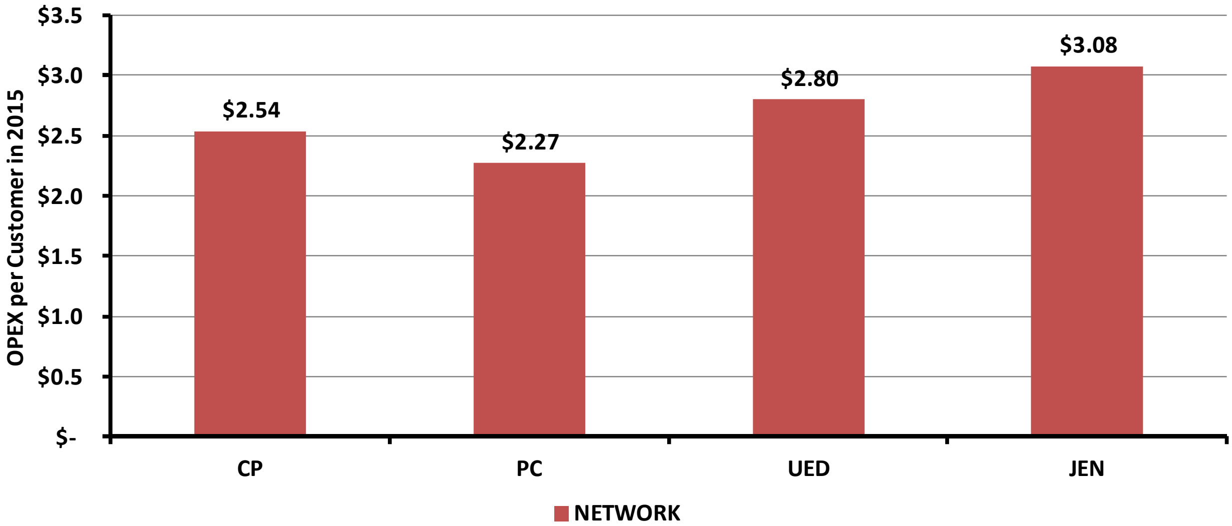

Figure 8 – DNSP Local Area Network Opex in 2015

As shown in Figure 8, CP-PAL's proposed level of communications opex for a mesh network is comparable to that of peer DNSPs. Energeia recognises that the communication networks are materially different, due to being a mixture of urban, suburban and rural topologies. Energeia also notes that CP-PAL's expenditure includes technology assurance costs, which are not reflected in JEN and UED line items.

In addition to its top-down assessment, Energeia reviewed the bottom up modelling by Deloitte, including the underlying activity levels assumed, and number and cost of FTEs. Energeia found CP-PAL's proposed resourcing levels and costs to be reasonable, except for the $[C-I-C] annual budget for [consulting] services. Energeia's view is that no reasonable commercial business would budget for $[C-I-C] per year for consulting costs, representing [C-I-C] % of the section's labour costs, without substantiation.

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82 See pages 177-180 of the Draft Determination
83 See pages 192-194 of the Draft Determination
84 See page 28 of the Deloitte report

Although the technology acceptance function was removed from PC-CP's revised AMI communications opex, Energeia's review has found that [C-I-C] FTEs for quality assurance in 2014-15 to be unreasonable. Energeia's view is that [C-I-C] FTEs would be reasonable for maintaining and operating the CP-PAL's technology acceptance lab, based on the resourcing assumptions of other Victorian DNSPs in the same circumstances.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's AMI communications opex as meeting the Commercial Standard test.

Based on its review of DNSP provided information, and examples from other deployments, Energeia assessed CP-PAL's technology acceptance capex in 2014-15 as not meeting the Commercial Standard test.

6.4 Resolving Issues

DNSPs were each sent 45-55 questions to address identified issues, with a requirement to respond within the minimum three business days due to tight timeframes. Energeia considered each DNSP's response, contacting them directly via telephone to address any remaining questions.

Energeia acknowledges the pressure these requests put on each DNSP, and would like to thank their regulatory managers in particular for their understanding, support and cooperation.

Appendix 1 – About Energeia

Energeia Pty Ltd (Energeia) based in Sydney, Australia, brings together a group of hand-picked, exceptionally qualified, high calibre individuals with demonstrated track records of success within the energy industry and energy specialist academia in Australia, America and the UK.

Energeia specialises in providing professional research, advisory and technical services in the following areas:

- Smart networks and smart metering
- Network planning and design
- Policy and regulation
- Demand management and energy efficiency
- Sustainable energy and development
- Energy product development and pricing
- Personal energy management
- Energy storage
- Electric vehicles and charging infrastructure
- Generation, including Combined Heat and Power (CHP)
- Renewables, including geothermal, wind and solar PV
- Wholesale and retail electricity markets

The quality of our work is supported by our energy-only focus, which helps ensure that our research and advice reflects a deep understanding of the issues, and is often based on first-hand experience within industry or as a practitioner of theoretical economic concepts in an energy context.

Energeia's Relevant Experience

Energeia's recent smart metering and smart grid related engagements are summarised below.

Review of Victorian DNSPs' 2009-11 Advanced Metering Infrastructure Budgets

The Australian Energy Regulator engaged Energeia to undertake a review of Victorian Distribution Network Service Providers' (DNSPs) 2009-2011 budget proposals for Advanced Metering Infrastructure against the regulatory criteria specified in the revised Order in Council.

Review of Advanced Metering Infrastructure Enabled Load Control Performance Levels

A Victorian DNSP engaged Energeia to undertake a review of current load control enabling performance levels and to make recommendations considering the impact of updated use case benefits and communications cost information.

Review of Overseas Regulation of Smart Metering Information for Customers

An Australian jurisdictional regulator engaged Energeia to review the arrangements in place in comparable overseas jurisdictions and the experience of EnergyAustralia during their roll out of interval meters and ToU pricing to nearly 140,000 customers using between 15MWh and 160MWh per annum (p.a.).

Best Practice Regulation of Smart Metering

A smart metering vendor engaged Energeia to identify policy and regulatory options for improving the smart meter deployment in Victoria. The engagement included a detailed review of leading international smart metering deployments in California, Texas, Pennsylvania, Ontario and Sweden.

International Smart Meter Based Energy Retailing: Review and Recommendations

A top-tier Australian energy retailer engaged Energeia undertake a review of international deployments of smart metering and ToU based products to identify innovation and key lessons learned. The purpose of the engagement was to identify innovative products that the retailer could consider deploying across its smart meter enabled customer base.

Smart Meter Enabled Retail Product Development and Trialling

An Australian energy retailer engaged Energeia to support the design, development, justification and trialling of three innovative smart meter enabled electricity pricing plans that would save customers money, improve the retailer's margin and reduce customer churn.

Smart Meter Enabled Network Product Development and Trialling

A NSW DNSP engaged Energeia to support the design, development, justification and trialling of innovative, smart meter enabled network tariffs that could reduce network investment costs, save end user customers money and improve retailer margins. The engagement included the design of a robust sampling approach that would enable the rigorous quantitative assessment of product impacts on key performance indicators.

Review of Advanced Metering Infrastructure Related Threats and Opportunities in Australia

A top-tier Australian energy retailer engaged Energeia to undertake a review of emerging threats and opportunities in the electricity sector as it transitions to a more intelligent platform (smart grid) over the next five to ten years. The key area of focus was the deployment of advanced metering infrastructure and related customer energy technologies, products and services.

Smart Grid Design and Development

Energeia was engaged by a major Australian utility to develop a smart grid solution for minimising the costs and carbon intensity of generating power in a remote island energy system. The engagement included designing a fit-for-purpose smart grid concept, developing functional and technical specifications, supporting market engagement, modelling project costs and benefits, and developing the project business case.

Smart Grid, Smart City Proposal Support

Energeia was engaged by a DNSP to support the development of their winning proposal for the $100M Smart Grid, Smart City project. The engagement included the development of a retailer value proposition and engagement strategy, development of the project's delivery and operating models, and development of related proposal documentation.

Network of the Future Design

A top tier field services provider engaged Energeia to support the development of a Network and Substation of the Future concept design and development roadmap. The engagement included researching international best practice, facilitating a number of concept development workshops with project stakeholders, developing the client proposal, and sourcing the skilled resources needed to deliver it.

Future Operating Model Design

An Australian DNSP engaged Energeia to support the development of their Future Operating Model blueprint and roadmap to 2026. The engagement included facilitating a series of whole-of-business workshops to gain strategic alignment on the DNSP's future customers, network and organisation, and the development of documentation to support stakeholder engagement and communication.

Embedded Networks for Electric Vehicles

Energeia was engaged by a leading electric vehicle infrastructure company to review the existing market arrangements around embedded networks and to provide recommendations regarding how these arrangements may be used to support the deployment of electric vehicle charging infrastructure.

Appendix 2 – Resumes of Key Personnel

EZRA BEEMAN

MANAGING DIRECTOR

SUMMARY OF EXPERIENCE

Ezra Beeman has consulted on business strategy, asset transactions, contract structuring, energy and information technology, market design and industry regulation for company directors, executives and managers of major oil, gas and power companies across Europe, the Americas and the Asia Pacific region.

Ezra's industry career has spanned a number of strategic and internal advisory roles where he helped propel EnergyAustralia into a position of international leadership in smart metering, products and services. During his time with the company, he built a reputation for tackling some of the company's toughest challenges and achieving exceptional results.

In addition to his consulting and utility executive experience, Ezra is an internationally recognized expert on advanced metering infrastructure, wholesale and retail markets, customer research, and demand response.

QUALIFICATIONS

- Masters of Applied Finance, Macquarie University, Australia
- Bachelor of Arts in Economics and Philosophy (Hons), Claremont McKenna College, USA

SUMMARY OF EXPERIENCE AT ENERGEIA

As the Managing Director, Ezra has overall responsibility for achieving the company's vision of becoming Australia's leading specialist consultancy and industry research firm. Ezra is responsible for setting and delivering the company's research agenda and developing new business. In this role his major achievements have been:

- Advising and supporting 21 companies pursuing ground-breaking outcomes in FY10, representing a broad cross-section of Australia's energy industry.
- Developing a 20 year industry roadmap for the establishment of a smart grid in Australia on behalf of the Electricity Networks Association (ENA).
- Authoring two chapters of the winning proposal for the $100M Smart Grid, Smart City project and contributing to its overall development.
- Developing a smart grid solution for minimising the costs and carbon intensity of generating power in a remote system on behalf of a major Australian utility.
- Reviewing over $2 billion in Victorian distribution network's smart grid budget proposals on behalf of the Australian Energy Regulator (AER).
- Creating a continuous improvement process for promoting best available technology for energy efficiency and carbon reduction on behalf of Newcastle City Council.
- Identifying international best practice in smart meter enabled retail pricing and related customer protections on behalf of a jurisdictional regulator.
- Developing a business plan and authoring a winning proposal for the supply of electrical vehicle charging infrastructure on behalf of an electric vehicle infrastructure provider.

- Creating a value framework, integrated network and retail price and benefits capture strategy to maximise the value of demand response on behalf of a new entrant retailer.
- Estimating the market and network value of demand response across a range of service levels on behalf of a Victorian DNSP.
- Identifying the key risks and opportunities related to smart metering and the emerging smart energy market strategy on behalf of an energy retailer.
- Authoring major studies of residential renewable generation, micro-combined heat and power, the smart energy market, personal energy management and electric vehicles.

SUMMARY OF EXPERIENCE ENERGY AUSTRALIA

As the A/Mgr – Alliance Strategy, Ezra was responsible for managing the implementation of two Alliances to deliver up to $1.5B in capital projects over five years. In this role his major achievements were:

- managing the legal and commercial negotiations to achieve commercial alignment, and developing a comprehensive Alliance implementation plan, including a resourcing model for $8B capital program

As the A/Executive Mgr – Strategic Services, Ezra was responsible for the coordination of the Executive team on behalf of the Executive General Manager, Network. His duties included:

- providing advice to the Executive General Manager, Network; Strategy development, business planning and divisional communication; performance measurement, monitoring and reporting; Board, ministerial and inter-divisional interfaces and coordination of the executive management team

As the Mgr – Network Metering & Pricing Strategy, Ezra was responsible for the formulation, justification and delivery of company's strategic pricing and metering initiatives. His responsibilities included:

- leading the development and delivery of the $500M Advanced Metering Infrastructure (AMI) strategy, which included Australia's largest technology pilot & customer research study
- driving the deployment of Australia's largest smart metering fleet and representing the Division during a $70M strategic metering procurement

As the Network Business Consultant, Ezra was responsible for internal business consulting, including:

- providing strategic advice to senior management on B2B, metering, pricing and retail services; managing retail market interfaces, including internal service providers; managing strategic initiatives including the Time-of-Use (ToU) / interval meter rollout; leading negotiations between EA Network, retailers and end-users, and increasing faltering ToU project output from 2,500/ year to 16,000/ year.

SUMMARY OF EXPERIENCE CAMBRIDGE ENERGY RESEARCH ASSOCIATES

As the Senior Associate, Global Gas & Power, Ezra provided expertise to the group's four regional gas and power teams. Projects included:

- overseeing the Asia Pacific gas and power component of a Board level strategy project; lead author of long-term N.A. gas scenarios study and editor and co-author of regional Latin American power sector briefings.

As an Associate Director, European Power, Ezra was a senior member of a team serving 50 clients. His role was responsible for the network sector, retail & wholesale markets and player strategy, ad-hoc client advisory service and new business development. In this role Ezra's achievements were;

- becoming the youngest Associate Director in the company's history; leading projects on retailer entry and a international investment framework; developing a pan-European pricing model for due diligence on $800M IPP; providing Board level due diligence to a major trading bank's generator investment in South Australia.

Ezra Beeman has published more than 15 articles and papers in his field of expertise.