Attachment 1.10

PWC - Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons, Jan 2015

January 2015

Ausgrid revised regulatory proposal attachment www.pwc.com.au

Ausgrid, Essential Energy and Endeavour Energy

Ausgrid, Essential Energy, Endeavour Energy

Appropriateness of RIN data for benchmarking

9 January 2015

Independent Expert Advice

Private and Confidential

pwc

Private and Confidential

Mr Matthew McQuarrie
Regulatory Reset Program Director
Ausgrid (on behalf of Ausgrid, Essential Energy and Endeavour Energy)

9 January 2015

Dear Matthew

Independent expert advice on appropriateness of RIN data for benchmarking comparisons

I, Cassandra Michie, of 201 Sussex Street, Sydney, am an Australian Fellow Chartered Accountant and a Partner of PwC's Forensic Services practice. I have over 25 years' experience as a Chartered Accountant, specialising in the area of forensic accounting and dispute analysis. Specific details of my qualifications and experience are set out in my curriculum vitae at **Appendix A** to this report.

Purpose of report

This report has been prepared at the request of Ausgrid, Essential Energy and Endeavour Energy (**the three NSW DNSPs**).

This work will assist the NSW DNSPs in responding to the Australian Energy Regulator's (**AER**) Draft Decisions, via their Revised Proposals due 13 January 2015.

To assist you in this task, you have requested me to provide independent advice (in the form of a Final Report) in relation to the potential for inconsistent data and the appropriateness of the benchmarking undertaken by the AER.

In particular, the NSW DNSPs are seeking independent advice on:

a) the differences in regulatory information provided by each DNSP in response to the AER's Regulatory Information Notices (**RIN**)

b) the impact of these differences within the AER's benchmarking study including whether the AER's analysis has adjusted for these differences

c) whether the benchmarking analysis, on which the AER has relied, is robust enough to assess the relative efficiency of productivity of the DNSPs in the National Electricity Market (**NEM**).

This report is not to be reproduced or used for any purpose other than as outlined above, without my or PwC Australia's written consent in each specific instance. My firm and I do not assume any responsibility for liability for any losses suffered as a result of the circulation, publication, reproduction or other use of this report contrary to the provisions of this paragraph.

Information relied upon

In order to prepare this report, I have referred to the information listed in **Appendix B**. In reaching my conclusions and opinions, I have made certain assumptions and been instructed to make certain assumptions.

The following scope of works was provided to PwC as part of this engagement:

1. Research the 'regulatory information' provided by the distribution network service providers to the AER in response to a regulatory information notices
2. Identify differences in 'regulatory information' provided in response to AER regulatory information notices
3. Review the impact of these differences within the AER's benchmarking study
4. Provide a report on these findings, including a comparison of reporting accuracies/degree of certainty of submitted data across DNSPs and the assumptions used as stated in relevant basis of preparations.

Disclaimer

Consistent with my duty under the Federal Court Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia, I reserve the right to review and amend all opinions included or referred to in this report and if I consider it necessary, to revise my report in the light of any information which becomes known to me after the date of this report or if additional sources of information not referred to in **Appendix B** are provided to me.

Other than as set out in this report, I have not verified the information presented to me nor done anything in the nature of an audit of the information given to me. Unless otherwise stated in this report, I have assumed the correctness of the documents upon which I have relied.

My calculations are based upon the information sourced from publicly available information. I have relied upon and not verified the truth or accuracy of all information or material provided or made available to me during this engagement. I do not assume any responsibility and make no representations with respect to the accuracy or completeness of any information provided by and on behalf of the three NSW DNSPs.

I have not performed anything in the nature of an audit of the information given to me other than as set out in this report.

Compliance

I confirm that in preparing this report, I have read, understood and complied with the Federal Court's expert witness guidelines *Practice Note CM7 – Expert Witnesses in Proceedings in the Federal Court of Australia*.

I have complied with the Accounting Professional & Ethical Standards Board (**APESB**) standard APES 215 "*Forensic Accounting Standards*".

In undertaking the work required to prepare this report, I was assisted by PwC staff working under my direction, however, all opinions in this report are my own.

In forming my opinion, I declare that, subject to the disclaimer above, I have made all the enquiries that I believe are desirable and appropriate and that no matters of significance which I regard as relevant have, to my knowledge, been withheld.

I confirm that each of my opinions set out in this report is wholly or substantially based upon my specialised knowledge.

PwC undertakes relationship checks prior to commencing each new engagement to determine what, if any, Professional Services the firm has undertaken for a client. I advise that the firm provides various professional services to the three NSW DNSPs however; I confirm that I have made appropriate enquiries and am not presently aware of any circumstances that, in my view, would constitute a conflict of interest or would impair my ability to provide assistance in this engagement. I confirm that neither I, nor PwC is providing, or has provided Professional Services related to this Engagement to the NSW DNSPs which threaten my obligation to comply with the fundamental principles of APES 110 *"Code of Ethics for Professional Accountants"* or my paramount duty to the Court.

I confirm that the financial terms of this engagement include a fee based upon normal hourly billing rates for staff allocated to this engagement, and that receipt of a fee for services rendered is not contingent upon any outcome of the matter referred to above.

The balance of this report is set out as follows:

Section	Description
1	Requirements of the National Electricity Rules
2	Appropriateness of benchmarking
3	Use of benchmarking
4	Quality of economic benchmarking data inputs
Appendix	**Description**
A	Curriculum Vitae for Cassandra Michie
B	Information relied on
C	Example of asset cost calculation
D	Summary of the basis of preparation documents for economic benchmarking

Executive Summary

Benchmarking is often used as a comparative tool to inform about the relative overall efficiency of distribution network service providers (**DNSPs**). International experiences suggest that caution is required when relying on the results of benchmarking for deterministic purposes.

This is particularly important if the data inputs are not accurate or based on estimates and if there are significant differences in the nature of the distribution businesses.

The Australian Energy Regulator (**AER**) in September 2013 sent economic benchmarking regulatory information notices (**RIN**) to all 13 DNSPs in the NEM requesting eight years of historic data (2006-2013), which was often backcast or estimated. This data included revenue, operating expenditure, asset base, operating environment, quality of service and operational data.

During consultation with the AER, the 13 DNSPs raised concerns with the provision of this data including:

- The RIN request did not contemplate the ability or otherwise of the businesses to provide or produce the requested information.
- Many businesses changed their systems over the eight year period including the financial and asset management systems which were used to source the RIN inputs.
- Many businesses changed their operating models and their operating and management sourcing arrangements over the period. Indeed there are many different ways in which this is carried out at a point in time in each of the 13 businesses let alone seeking meaningful comparisons over time.

Due to these issues, the structure and records of both financial and operational data was adjusted or reallocated by the DNSPs to fit the RIN requirements, which were set by the AER. Estimated information was provided in instances where information was not available or not recorded in the form required by the RIN. The Energy Networks Association (ENA) has concluded that much of the historic data provided by its members is unlikely to be sufficiently precise to be reliable for benchmarking purposes.[1] As a consequence of these issues, the results of benchmarking are potentially unreliable or misleading.

Further we have identified significant differences between the 13 DNSPs that raise the risk of inaccurate benchmarking such as: differences in vegetation management practices, related party arrangements and cost allocation methods.

The NSW DNSPs – Ausgrid, Essential Energy and Endeavour Energy – engaged PwC to review the data inputs and consider the appropriateness of the benchmarking undertaken by the AER. This report identifies issues with the data relied on by the AER for benchmarking purposes. My scope of work did not include the qualification of the financial impact of these issue, further it would not have been possible due to the time available to respond to the AER's draft determination and the complicated nature of the AER's benchmarking. However, where possible we have provided a view about whether the differences in RIN data would likely result in material impacts on the benchmarking.

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[1] Energy Networks Association, *Regulatory Information Notices to collect information for economic benchmarking, Submission on Draft RIN and Explanatory Statement*, 18 October 2013, page 1.

Issues that have been identified as having a potentially high impact and in my opinion should be considered by the AER when assessing the efficiency of the network businesses are summarised in Figure 1 below.

Figure 1 – Potentially high impact with economic benchmarking RIN data

a. the RAB allocation into capital inputs was subject to interpretation

b. weather adjusted demand was estimated by the businesses

c. differences in vegetation management practices in each jurisdiction

d. inputs used to calculate network length were subject to interpretation

e. cross ownership and related party arrangements

f. differences in cost allocation methods and capitalisation policies

g. differences in accounting methodologies and application of accounting standards

Each of these issues is discussed further in Chapter 4 of this report. The remainder of this report is structured as follows:

- Chapter 1 outlines the requirements of the National Electricity Rules including the role of benchmarking.
- Chapter 2 outlines key considerations relating to the appropriateness of benchmarking including the preconditions necessary for robust benchmarking results.
- Chapter 3 outlines the AER's reliance on benchmarking techniques when assessing the efficiency and prudency of forecast expenditure for the NSW DNSPs.
- Chapter 4 outlines the issues identified with the data inputs relied on by the AER including differences in interpretation, estimation techniques and allocation policies.

1 Requirements of the National Electricity Rules

In accordance with the National Electricity Rules, the AER is responsible, for the economic regulation of distribution services in the NEM.

Under the National Electricity Rules, the AER is required to include a DNSP's forecast operating expenditure in the Annual Revenue Requirements if it is satisfied that the expenditure reasonably reflects the efficient and prudent costs to achieve the **operating expenditure objectives** as per clause 6.5.6(a) of the National Electricity Rules as set out below.[2]

1) *meet or manage the expected demand for standard control services over that period;*
2) *comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
3) *to the extent that there is no applicable regulatory obligation or requirement in relation to:*
   i. *the quality, reliability or security of supply of standard control services; or*
   ii. *the reliability or security of the distribution system through the supply of standard control services,*

   to the relevant extent:

   iii. *maintain the quality, reliability and security of supply of standard control services; and*
   iv. *maintain the reliability and security of the distribution system through the supply of standard control services; and*
4) *maintain the safety of the distribution system through the supply of standard control services.*

The AER **must** accept the forecast operating expenditure if it is satisfied that it reasonably reflects each of the following **operating expenditure criteria**:

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

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2 National Electricity Rules, section 6.5.6(c).
3 National Electricity Rules, section 6.5.6(c).

In deciding whether or not the AER is satisfied that the criteria have been met, the AER **must** have regard to the following **operating expenditure factors** as set out in clause 6.5.6(e) of the Rules[4]:

- *the most recent annual benchmarking report and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period;*
- *the actual and expected operating expenditure of the DNSP during any preceding regulatory control periods;*
- *the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers;*
- *the relative prices of operating and capital inputs;*
- *the substitution possibilities between operating and capital expenditure;*
- *whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the DNSP;*
- *the extent the operating expenditure forecast is referrable to arrangements with a person other than the DNSP that, in the opinion of the AER, do not reflect arm's length terms;*
- *whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project;*
- *the extent the DNSP has considered, and made provision for, efficient and prudent non-network alternatives; and*
- *any relevant final project assessment report;*
- *any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal, is an operating expenditure factor.*

The operating expenditure factors set out the matters that the AER must take into account when considering the efficiency and prudency of forecast expenditure.

Clause 6.5.7 of the Rules set out the **capital expenditure objectives** (section 6.5.7(a)), the capital expenditure criteria (clause 6.5.7(c)), and the capital expenditure factors that the AER must take into account when assessing forecast capital expenditure. The capital expenditure factors are similar to the operating expenditure factors outlined above.

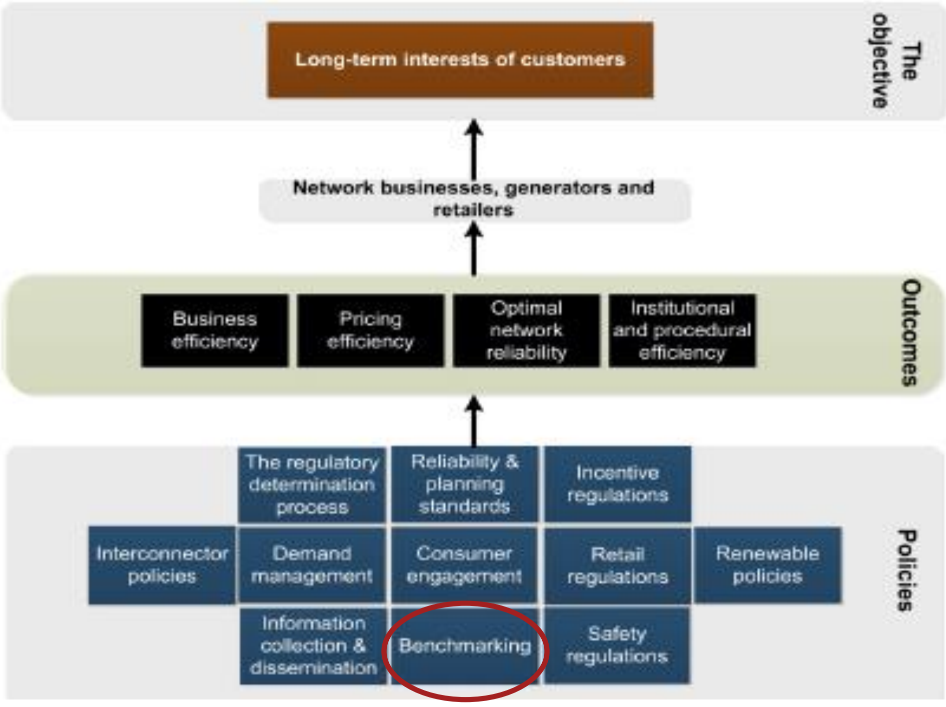
Use of benchmarking

Benchmarking is one tool available to the AER to assess the efficiency and prudency of forecast capital and operating expenditure. The Productivity Commission explains that benchmarking is 'one small piece of the complex regulatory regime' (see Figure 2).[5]

4 National Electricity Rules, section 6.5.6(e).

5 Productivity Commission, *Electricity Network Regulatory Frameworks*, Report No. 62, Canberra, 2013, page 8.

Figure 2 – Overview of the regulation of electricity networks



Source: Productivity Commission, Electricity Network Regulatory Frameworks, Report No. 62, Canberra, 2013 page 8.

As outlined by the Productivity Commission, the regulatory regime is designed to balance the use of each policy in order to meet the four outcomes of the regulatory regime, notably,

- business efficiency
- pricing efficiency
- optimal network reliability
- institutional and procedural efficiency.

The AER in its Expenditure Forecasting Guideline states that there are a number of assessment techniques available to assess the reasonableness of the forecasts. These techniques include: benchmarking, methodology review, governance and policy review, predicative modelling, trend analysis, cost benefit analysis and detailed project review.[6]

When considering the use of benchmarking the AER has committed to considering the following assessment principles[7]:

- **Validity** – must be appropriate for what needs to be assessed.
- **Accuracy and reliability** – produces unbiased and consistent results.
- **Robustness** – if the technique remains valid under different assumptions, parameters and initial conditions.
- **Transparency** – must be able to assess the results in the context of the underlying assumptions, parameters and conditions.

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6 AER, *Expenditure Forecasting Guideline*, November 2013, page 12.
7 AER, *Expenditure Forecasting Guideline*, November 2013, page 15.

- **Parsimony** – preference for simpler techniques over complex techniques.
- **Fitness for purpose** – use the appropriate technique for the task.

In its draft determinations for the NSW DNSPs, the AER has relied on benchmarking in a deterministic nature for assessing the efficiency of the forecast operating expenditure despite acknowledging the following constraints:

- issues with the quality of the economic benchmarking RIN data
- the differences between the businesses and their operating environments
- factors outside of the control of the businesses.[8]

I note that these issues were not quantified by the AER, so it is not possible to determine the financial impacts and the impact on the efficiency measures calculated by the AER.

The AER's reliance on benchmarking techniques, in light of these assessment principles, is considered in Section 3.

[8] AER, *Ausgrid Draft Decision 2015-19, Attachment 7 – Operating Expenditure*, page 43.

2 *Appropriateness of benchmarking*

As discussed below, for regulators to reasonably rely on benchmarking to help set forecast capex and opex requires high quality, reliable data inputs.

Benchmarking can be broadly defined as the comparison of efficiency and productivity performance against a reference or benchmark performance. The results from statistical benchmarking methods help to determine the relative efficiency of an individual company's operating costs and service quality relative to their peers.[9]

To undertake this comparison of efficiency well, regulators need to have access to good quality data sets. In this case, the AER has relied on the data is has collected using Regulatory Information Notices, which has been collected under a time constrained process.

The economic benchmarking RIN requests were provided to the DNSPs at the end of November 2013. The DNSPs provided an unaudited response in early March 2014 with final audited responses submitted to the AER on 28 April 2014.

During March to mid-April the AER conducted a 'data checking and validation process' whereby they liaised with the DNSPs in relation to the unaudited responses, progressively refining the data request by identifying errors and inconsistencies in the unaudited data.[10] The NSW DNSPs have advised PwC that this iteration process with the AER continued until the week of 11 April 2014, leaving less than two weeks for the final data set to be audited and signed off by authorising representatives of the businesses (including statutory declaration). This time constrained process led to fragmented responses and did not provide enough time for the DNSPs to respond to the AER's queries and concerns. This constrained process could lead to errors in the data set or unnecessary estimations.

In order to understand whether the AER's benchmarking data is of good quality, I have reviewed the AEMC's relevant determinations, the Productivity Commission's report on benchmarking and international benchmarking activities.

As part of the Amendments to the National Electricity Rules in 2012, the Australian Energy Market Commission (AEMC) considered the role of benchmarking. The AEMC considered that benchmarking could be used as a comparative tool to inform assessments about the relative overall efficiency of proposed expenditure, with the aim of providing ***'a high level overview taking into account exogenous factors'***.[11]

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9 Jamasb, T. and Pollitt, M. (2000). *Benchmarking and Regulation: International Electricity Experience,* 9(3), pp. 107-130.

10 AER, Explanatory Statement for the Draft RIN, page 10.

11 AEMC, Eco*nomic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services*, Final Position Paper, 15 November 2012, Sydney Page 85.

In this review, the AEMC stressed the importance of quality data collection for benchmarking[12] and that the benchmarking outcome was to provide a high level overview. The AEMC does not extend benchmarking to be solely determinative of forecast expenditure.

The Productivity Commission has highlighted the difficulty in distinguishing between inefficiency and errors arising from model misspecification, poor data, different regulatory settings and varying operating environment.[13] This is of particular relevance given the AER's reliance on benchmarking in these Draft Decisions to substitute alternative expenditure forecasts in place of the DNSP's proposal.

Following a rule change request from the Minister for Energy and Resources (Victoria), the AEMC set out the necessary preconditions for benchmarking recognising the importance of a robust dataset.[14]

> *If data is incorrect or inconsistent, the benchmarking results will reflect the errors, inconsistencies and gaps in the dataset*[15]
>
> *Australian Energy Market Commission, 2011*

In order to ensure that benchmarking is fit for purpose, the AEMC set out the following preconditions:

- **long term reliable information** that allows a sample of businesses to be compared
- data must be **high quality** when applying benchmarking
- consistent **time series data** is required
- **consistent definitions** in the way input/output quantities are reported.

In my opinion, these are a reasonable set of preconditions to help assess the quality of a dataset being proposed for use in benchmarking. When reviewing the AER's benchmarking data I considered whether there is an indication that the data meets these preconditions.

In 2013, the Productivity Commission assessed the use of benchmarking as a means of achieving the efficient delivery of network services to meet the long term interests of consumers. As part of this review, the Productivity Commission provided advice on how benchmarking could be used to enhance efficient outcomes, including setting out a framework for the benchmarking of electricity networks in the NEM.

The Productivity Commission explains that judging benchmarking involves balancing various criteria most notably: accuracy, reliability and robustness (see Figure 3).

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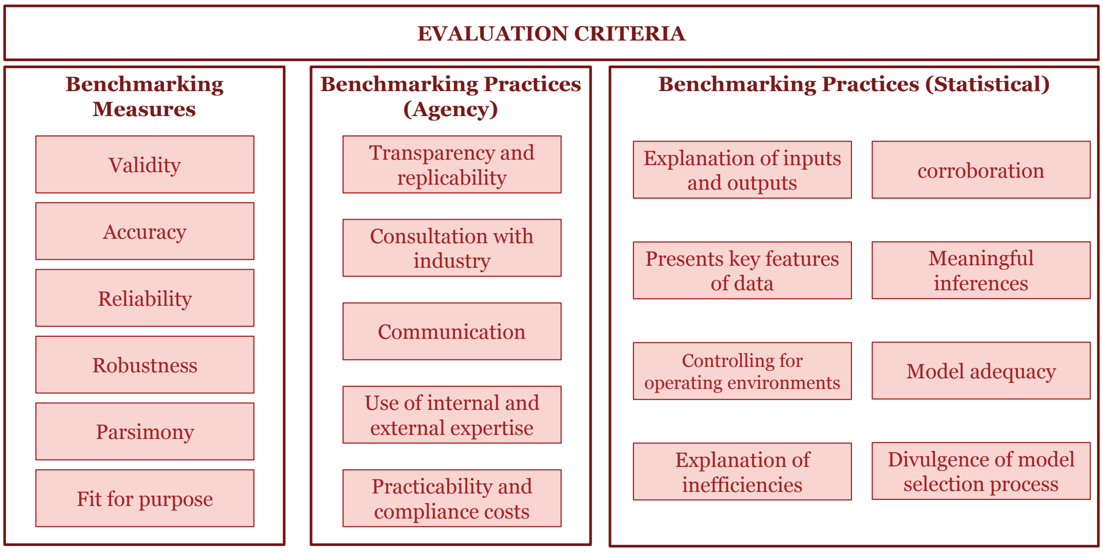
12 AEMC, *Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services*, Final Position Paper, 15 November 2012, Sydney Page 86.

13 Productivity Commission, *Electricity Network Regulatory Frameworks*, Report No. 62, Canberra, 2013, page 29.

14 AEMC, *Total Factor Productivity for Distribution Network Regulation, Rule Determination*, 22 December 2011, Sydney, page 16.

15 AEMC, *Total Factor Productivity for Distribution Network Regulation, Rule Determination*, 22 December 2011, Sydney, page 16.

Figure 3 – Evaluation criteria for assessing benchmarking practices



Source: Productivity Commission, Electricity Network Regulatory Frameworks, Report, No. 62, Canberra, 2013, page 167.

> *Data inputs into benchmarking models are subject to error due to measurement problems, small differences in the definitions used by the businesses and the period to which the data relates, and simplification of the relationship between costs, inputs and outputs*
>
> *Productivity Commission, 2013*

Benchmarking practices in other countries

A range of Australian and international regulators have stated views about the use of benchmarking, which all make conclusions that the underlying data needs to be of the highest quality. The AER and ACCC's 2012 review of international regulatory practices in benchmarking opex and capex in energy networks concluded that the quality of data is an important consideration in benchmarking, with implications for the choice of the type of benchmarking employed as well as the applicability of the results.[16]

This review also noted service quality has generally not been included in cost benchmarking models as it is difficult in practice due to either data limitations or technical model estimation issues.[17]

Jurisdiction specific findings of the review included:

- Ofgem, the electricity and gas regulator in the UK, notes that econometric models and benchmarking techniques cannot provide robust efficiency assessment in isolation. It therefore used its judgment to make adjustments to ensure that the data was comparable when considering the benchmarking results as part of its 2008 revenue determination.[18]

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16 Research Team from the AER and the ACCC, *Regulatory practices in other countries: Benchmarking opex and capex in energy networks*, May 2012, page 3.

17 Ibid, page 3.

18 Ibid, page 27.

- New Zealand's Ministry of Economic Development noted in 2007 that its use of thresholds and comparative benchmarking, while useful as a diagnostic tool, when backed by the threat regulatory control can create strong disincentives. Where the benchmarking is based on backward-looking information and does not take into account the forward-looking circumstances of individual firms, it can discourage otherwise efficient investment decisions as firms may avoid making expenditures that would be efficient, in order to improve their result when benchmarked.[19]
- Lessons from the Netherlands' use of benchmarking in the first regulatory period (2001-2003) included the quality of the data used in benchmarking can be central to disputes.[20]
- Benchmarking in Canada can be difficult given the differences in climate, design standards, regulatory regime and number of customers which makes it hard to control for the consequential differences in factors.[21]

Section 4 of this report raises concerns with the quality of the data relied on by the AER for benchmarking purposes. International experiences highlight the need for benchmarking data to be well developed and of high quality.

Based on PwC's analysis and research the key lessons and experiences include:

- *The data inputs used for benchmarking should be of high quality with minimal levels of estimated information.*
- *If the quality of the data inputs is poor, benchmarking should not be considered in isolation. The regulator should use its judgement when considering the benchmarking results.*
- *An unintended consequence of benchmarking is that backward looking analysis can discourage otherwise efficient investment decisions as businesses may avoid expenditure in order to improve their results when benchmarked.*
- *Consistent definitions and interpretations of the data inputs are essential to ensure robust benchmarking results.*
- *Long term reliable information is required in order for benchmarking results to be reputable.*

Further as noted in Section 4, I have identified a number of issues with respect to the accuracy of the benchmarking data inputs provided by the DNSPs in the NEM for the purposes of economic benchmarking.

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19 Ibid, page 110.
20 Ibid, page 140.
21 Ibid, page 150.

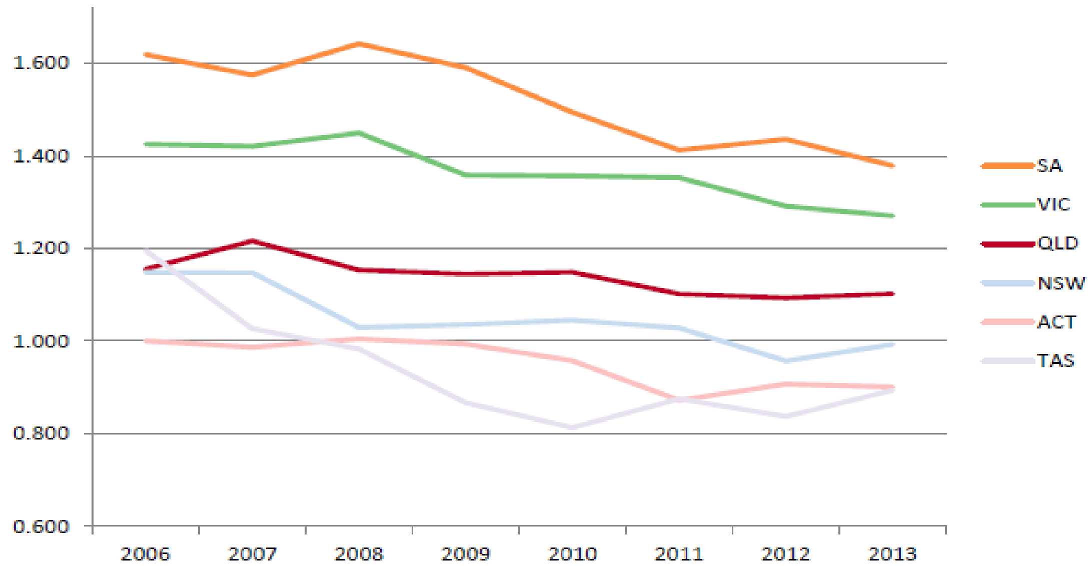
3 *Use of benchmarking*

The AER has relied on results from benchmarking analysis to reduce the revenue allowances of the NSW DNSPs by an average of 33 per cent for the 2015-19 regulatory control period.

On 27 November 2014, the AER released its first Annual Benchmarking Report for the electricity DNSPs. In this report, the AER set out the relative efficiency of the DNSPs, including how their productivity compares at the aggregate level and for the outputs they deliver to consumers. The AER attempted to measure the efficiency of each business in the NEM in using inputs to produce outputs by comparing current performance to historic performance. The AER presents the results of two benchmarking techniques, multilateral total factor productivity (MTFP) and partial performance indicators (PPI). The AER examines the efficiency of the DNSPs between 2006 and 2013.

From the results of the benchmarking analysis the AER has concluded that the NSW DNSPs are amongst the least efficient in the National Electricity Market (NEM).[22] Figure 4 presents the results of the AER's MTFP analysis, which measures productivity by constructing a **ratio of outputs produced over inputs used**. In this instance, the AER measured the **outputs** (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length) against the **inputs** (operating expenditure (opex) and capital expenditure (capex)) for each business in the NEM.[23] The higher the ratio of outputs over inputs, the more efficient the business is.

Figure 4 – Results of the AER's MTFP benchmarking analysis



Source: AER, Annual Benchmarking Report – Electricity Distribution Network Service Providers, Nov 2014, page 6.

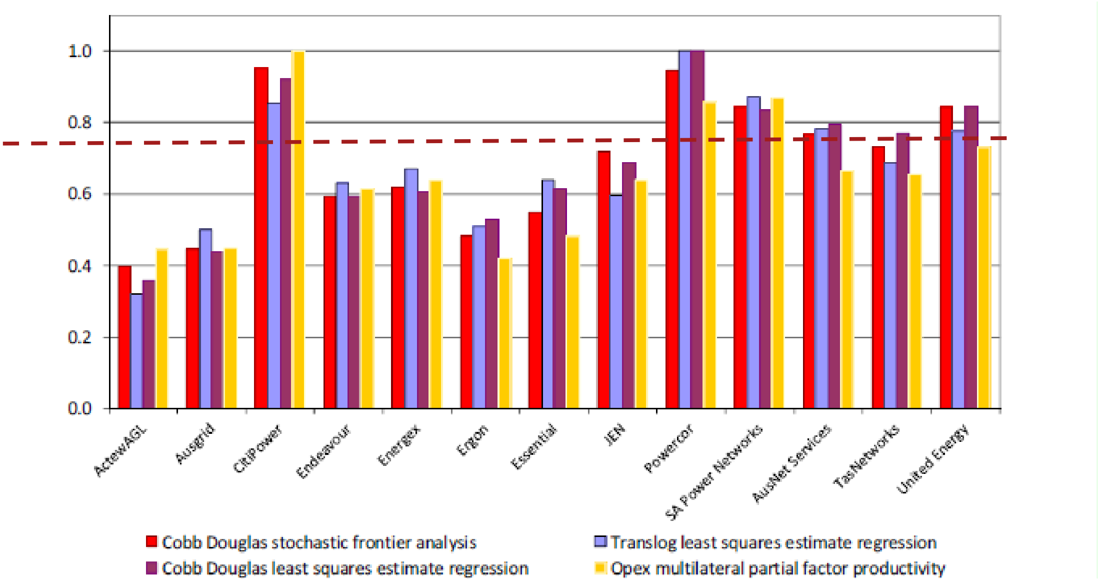
22 AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2014, page 6.

23 Ibid, page 28.

In its Draft Decisions for the NSW DNSPs, also released on 27 November, the AER concluded that each NSW DNSP has the opportunity for the provision of more efficient services. In its Draft Decisions, the AER did not accept forecast capital and operating expenditure as proposed by the NSW DNSPs, choosing to substitute alternative estimates of future expenditure.

In assessing the efficiency of operating expenditure, the AER developed several techniques for assessing the relative efficiency of the DNSPs compared to their peers.[24] Four techniques were used to measure opex performance, including: stochastic frontier analysis, two forms of least squares estimate regression analyses and multilateral partial factor productivity. The AER's Draft Decisions compared the efficiency of the NSW DNSPs to a weighted average of all networks with efficiency scores above 0.75 using these econometric modelling techniques to benchmark historical opex. This '**efficiency reference group'** includes CitiPower, Powercor, United Energy, SA Power Networks and AusNet Services. As with the MTFP analysis, the higher the efficiency score, the more efficient the business is.

Figure 5 –Benchmarking of Historical Opex across the NEM



Source: AER Draft Decision, Ausgrid 2015-19, Overview, page 55.

When assessing the proposals and historical **capital expenditure** performance, the AER concluded that significant reductions would be required to bring the NSW DNSPs in line with their peers.[25] Similarly, in its analysis of **operating expenditure**, the AER concluded that there was an efficiency gap in performance between the NSW DNSPs and the majority of their peers.[26]

In its Draft Decisions, the AER did not accept the forecast capital and operating expenditure as proposed by the NSW DNSPs, choosing to substitute alternative future expenditure. This led to revenue reductions of 30% to 35% for the NSW

[24] AER, *Ausgrid Draft Decision 2015-19, Attachment 7 – Operating Expenditure*, page 30.

[25] AER *Draft Decisions, 2015-19, Overview,* Ausgrid - page 51, Essential Energy– page 53, Endeavour Energy – page 53.

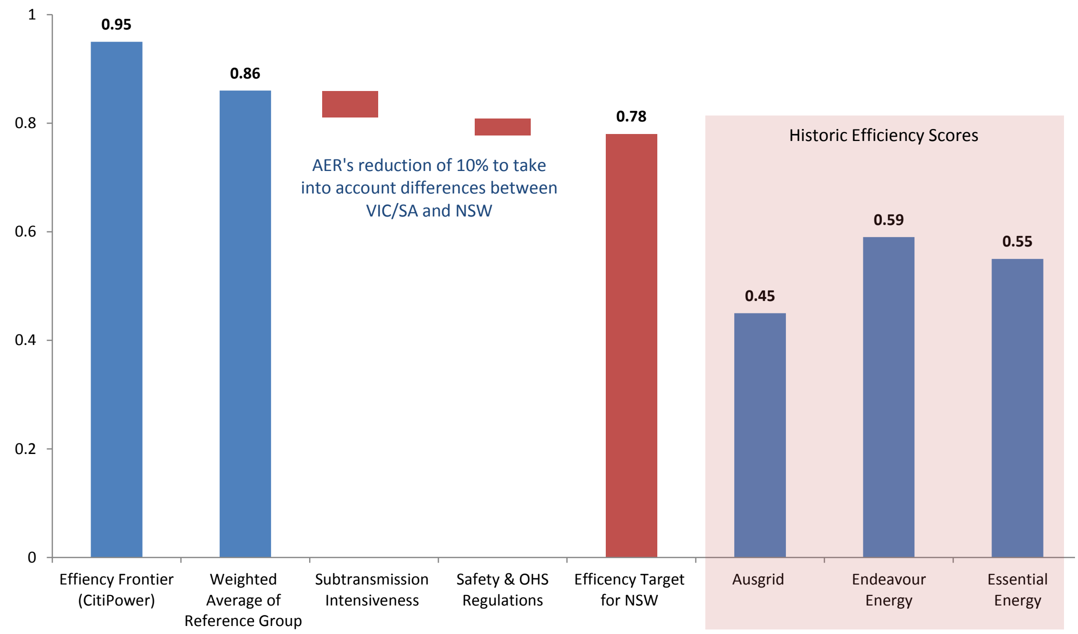
[26] AER *Draft Decision, 2015-19, Overview*, Ausgrid - page 51, Essential Energy – page 53, Endeavour Energy – page 53.

DNSPs. Collectively, the NSW DNSPs' revenue was reduced by **$6.69 billion** over the next five years.

AER's reliance on benchmarking results

The AER's Draft Decisions set an efficiency target of **0.78** for the three NSW DNSPs following the benchmarking of networks in the NEM.[27]

Figure 6 – AER's methodology in setting the efficiency target for NSW



Source: Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, Prepared for the AER, 17 November 2014.

In setting the efficiency target for the NSW DNSPs, the AER took into account the following factors:

- the **network density** of the businesses including energy delivered, ratcheted maximum demand, customer numbers and line length – via modelling techniques
- the **relative share of underground cables** between the businesses – via modelling techniques
- jurisdictional differences to **subtransmission intensiveness** – via a manual adjustment of 5 basis points
- jurisdictional differences in **OH&S Regulations** – via a manual adjustment of 3 basis points.

27 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, Prepared for the AER, 17 November 2014.

The AER also identified differences between the businesses in the NEM that it deemed to be immaterial when benchmarking the efficiency of historic expenditure including:

- system complexity
- the treatment of provisions
- share of single stage transformation capacity.[28]

I consider that the AER's methodology has not adequately taken into account important differences between the businesses and has not considered the quality of the data inputs provided by the DNSPs. The issues with the data inputs provided by each DNSP are explored further in Section 4.

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[28] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, Prepared for the AER, 17 November 2014.

4 Quality of economic benchmarking data inputs

The network businesses have highlighted concerns with the data inputs provided as part of the Economic Benchmarking RIN process to the AER.

PwC has reviewed the Basis of Preparation for the economic benchmarking data for the NSW DNSPs and the five DNSPs in the efficiency reference group as determined by the AER (CitiPower, Powercor, AusNet Services, United Energy and SA Power Networks). PwC also reviewed the cost allocation methods and corporate structures of these businesses. Information about the region and size of each business is provided in Table 1.

Table 1 – DNSPs considered as part of this review

DNSP	Region	Ownership	Asset base
CitiPower	VIC (Melbourne CBD)	Spark Infrastructure (49%), Cheung Kong Infrastructure Holdings and Power Assets Holdings (collectively 51%)	$1.9b
Powercor	VIC (West and South Western Suburbs)	Spark Infrastructure (49%), Cheung Kong Infrastructure Holdings and Power Assets Holdings (collectively 51%)	$3.3b
United Energy	VIC (South Eastern Suburbs, Mornington Peninsula)	DUET (66%), Singapore Power International Holdings (34%)	$1.9b
AusNet Services	VIC (Eastern/ North Eastern Suburbs, Eastern Victoria)	Private (49%), Singapore Power (31%), State Grid (19%)	$5.6b
SA Power Networks	SA	CKI / Spark Infrastructure	$3.9b
Endeavour Energy	NSW (South Sydney)	NSW Government	$6.0b
Ausgrid	NSW (Sydney CBD and Nth)	NSW Government	$15.2b
Essential Energy	NSW (other)	NSW Government	$7.2b

Source: AER, State of the Energy Market 2013, page 63.

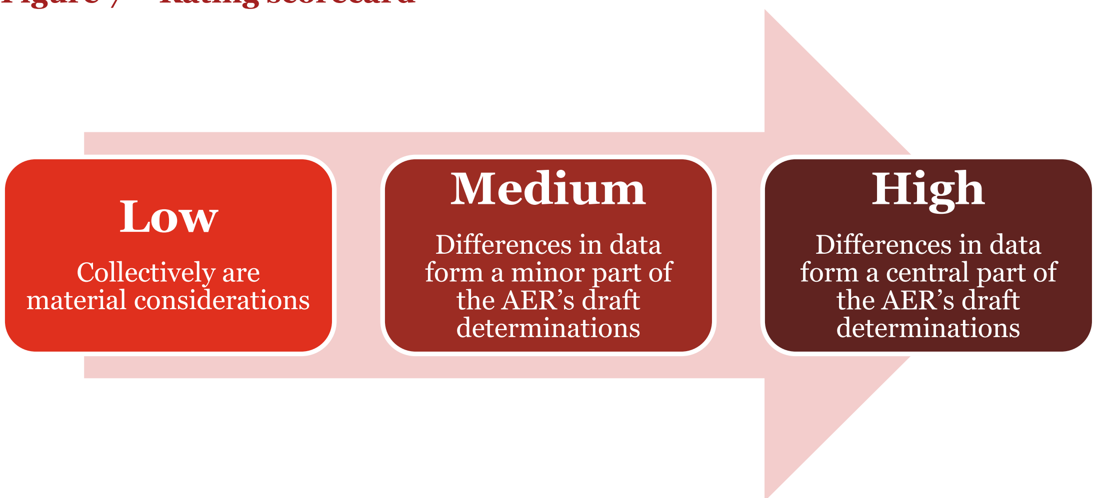
Our approach is to identify, from statements in the Basis of Preparation documents and from the examination of the RIN data, differences in interpretation or estimations of the data provided. In general, I considered:

- the differences in the preparation of the economic benchmarking RIN templates
- the differences in the approved cost allocation methods of each business
- the accounting standards and methodologies as outlined in the financial statements and annual reports of each business during 2009 to 2013
- consideration of exogenous factors that are outside of the businesses' control including differences in operational practices, guidelines and legislative requirements.

The potential impact of these differences was then considered utilising the following ratings:

- **High** – significant differences in data which form a central part of the AER's recent draft determinations.
- **Medium** – differences in data which form a minor part of the AER's recentdraft determinations.
- **Low** – issues that are each minor but collectively could lead have a material impact.

Figure 7 – Rating scorecard



This is not a review of whether the data is compliant; the assessment process has assumed compliance with the AER's instructions. This review considers whether the data is fit for purpose and the suitability of the data for benchmarking purposes. Further this report has not quantified the value of issues identified.

Issues identified with the data inputs

This section provides an overview of the differences in interpretation, and estimation techniques that may lead to the data not being comparable.

I considered:

- the method by which the data was obtained by the DNSPs
- assumptions, definitions and exclusions applied by the DNSPs
- accuracy of the data provided by each DNSP (based on their self-assessment)
- the preconditions for good benchmarking established by the AEMC.

I have identified issues with the data inputs used by the AER for benchmarking purposes. These issues were identified in the context of the AER's benchmarking results and Draft Decisions for the NSW DNSPs.

There are seven issues that have been given a ***high*** rating, which in my opinion means a correction should be made and considered when assessing the efficiency of the network businesses, including:

a) the RAB allocation into capital inputs was subject to interpretation

b) weather adjusted demand was estimated by the DNSPa

c) differences in vegetation management practices in each jurisdiction

d) inputs used to calculate network length were subject to interpretation

e) cross ownership and related party arrangements

f) differences in cost allocation methods and capitalisation policies

g) differences in accounting methodologies and application of accounting standards.

These data quality issues directly impact the AER's benchmarking results as they are a central part of the MTFP and PPI analysis. For example, cost allocation methods and capitalisation policies directly affect the opex and capex incurred of a DNSP, which are network inputs into the AER's MTFP and PPI analysis.[29] Similarly, network length, in particular route line length, is a key DNSP output of the AER's MTFP analysis.[30]

I have assessed each of these issues against the AEMC's preconditions outlined in section 2 of this report to help objectively determine the quality of the data in question. Individually these issues may not be material, however collectively they could be substantial and should be considered when benchmarking the efficiency of the DNSPs.

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29 AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2014, page 17.

30 AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2014, page 13.

Issues identified that received a ***low*** or ***medium*** rating include:

- differing treatment of metering costs depending on jurisdictional requirements
- the techniques used to estimate the service lives of various asset classes were different between the DNSPs
- calculations of energy density and customer density were inconsistent between the DNSPs
- different approaches to the disaggregation of revenue into customer classes were utilised
- revenue from incentive schemes including the EBSS and STPIS, was estimated
- historic transformer capacity data was estimated
- a direct reconciliation of spatial data and billing data was not possible
- the relative age of the networks was not taken into account
- differing service quality and reliability standards
- differing energy fuel mix in each network including gas and solar penetration levels.

a) RAB allocation subject to interpretation

The economic benchmarking RIN data requested the Regulatory Asset Base (RAB) to be allocated into 10 categories including:

- overhead distribution assets less than 33kV(wires and poles)
- underground distribution assets less than 33kV (cables, ducts)
- distribution substations including transformers
- overhead assets 33kV and above (wires and towers / poles)
- underground assets 33kV and above (cables, ducts)
- zone substations
- easements
- meters
- other assets with long lives
- other assets with short lives.

These categories are different to the existing regulatory reporting framework required by the AER which include:

- distribution system assets
- subtransmission
- metering
- non-network general assets – IT
- non-network general assets – other
- public lighting
- SCADA / network control.

The economic benchmarking RIN requested the RAB to be allocated differently to the allocation required in the roll forward model for AER's draft determinations. The disaggregation of the RAB required for the economic benchmarking RIN is more detailed than the allocation for the existing reporting requirements. As such, the businesses have found the allocation of the RAB to be an area of difficulty.

> *The benchmarking RIN has introduced new reporting asset categories and methodology which the business has never been asked to report earlier. The business cannot directly allocate information for the network assets and therefore has to derive estimates for the benchmarking RAB financial information based on allocation of historically reported RAB financial information.*
>
> *Powercor, Economic Benchmarking RIN Basis of Preparation, page 57*

This disaggregation of assets has led to a risk of an inappropriate allocation of assets. In accordance with the AER's Final RIN Instructions and Definitions:

- 'subtransmission category' should be equivalent to overhead and underground assets 33kv and above
- 'distribution system assets category' should be equivalent to overhead and underground assets less than 33kv including zone substations and easements.[31]

Due to the different allocation techniques, there is not consistency in the data sets provided by the businesses. For example, the difference between these data sets for AusNet Services and United Energy is provided in Table 2.

Table 2 – Differences in RAB categories

	EDPR Roll Forward Model	Economic Benchmarking RIN	Difference (%)
AusNet Services			
Distribution system assets	$1,737,341	$1,795,136	**3%**
Subtransmission assets	$200,223	$72,337	**177%**
United Energy			
Distribution system assets	$936,965	$1,038,153	**10%**
Subtransmission assets	$376,203	$275,014	**37%**

Source: Economic Benchmarking RIN templates; Victorian Electricity Distribution Price Review, AER Final Decision 2011-15, Roll Forward Models.

The data sets are internally inconsistent due to the estimations and allocation approaches used by each business. Examples of different approaches undertaken by the DNSPs to provide the disaggregated RAB data include:

- **United Energy** allocated the RAB based on the results of an independent valuation of network assets for insurance purposes (from 2011).[32]
- **Ausgrid** allocated the RAB based on the optimised replacement cost of each asset class.[33]
- **Endeavour Energy's** methodology reflected the relative underlying service potential and the relative residual financial value of each asset class.[34]

Other issues with relying on the RAB for benchmarking

The RAB is a regulatory construct and was not constructed as the sum of a series of detailed pieces that match one-to-one with physical parts of each network. AusNet Services explains that it is not possible to say as a fact what share of its RAB is 'overhead distribution assets' or 'easements'.[35]

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31 AER, *Final RIN for economic benchmarking (example)*, Instructions and definitions, page 47.
32 United Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 15.
33 Ausgrid, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 22.
34 Endeavour Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 26.
35 SP AusNet, Letter to Chris Pattas, Draft Economic Benchmarking RIN, 18 October 2013.

The calculation of the initial RABs across the jurisdictions also differed, for example, the initial RAB values in Victoria included a balancing factor to take into account the cross-subsidies between rural and urban networks. As Fearon and Moran explain, this approach involved a single "one off" revaluation adjustment to the businesses' asset base – an upward adjustment in the case of the three urban businesses and downward in the case of the two rural businesses. The cross subsidy was, in effect, capitalised as a one-time adjustment.[36] Additionally, some components of the electricity networks in Victoria were provided with a nominal value, despite being fully depreciated to take into account the services provided by these assets.

Since their establishment, the RAB's have been rolled forward using different methodologies. In NSW IPART rolled the asset base forward using its methodology until 1 July 2009 and then the AER accepted the value and adopted its own roll forward approach using 'regulatory depreciation'. In other states the jurisdictional regulators all had their own approaches prior to the AER commencing the economic regulation of DNSPs across the NEM.

The roll forward of each DNSPs RAB has added capital and been depreciated according to different methodologies. This roll forward adds capital and depreciates the assets based on the regulators' approaches. While the amount of capital varies by DNSP, each RAB have been set to establish the efficient capital invested by each business that should be paid for by customers. This means that each DNSP's return on and return of capital (used in the AER's benchmarking) is efficient for the level of capital invested despite the inherent differences. The AER's capex and opex reductions, its Draft Determinations, were supported by the benchmarking results which were affected by the RIN data in question.

I consider the RAB data used by the AER does not meet the AEMC preconditions:

- The RAB data is not ***long term reliable information*** because each DNSP has been assessed by different regulators over time using different methodologies so the RAB data is not necessarily consistent over time.
- The RAB data is not ***high quality*** because it is a constructed dataset that equals the efficient capital to be funded by customers as determined by the relevant regulators. When applying RAB data in benchmarking, the benchmarking should conclude that each DNSP's RAB should be considered, given the nature of the RAB, to be the efficient capital input for each DNSP despite any differences in the magnitude of the RAB.
- The RAB data is not consistent ***time series data*** as noted above, each jurisdiction has established different opening RAB values and each regulator has rolled forward RAB values in different ways.
- The RAB data is not based on ***consistent definitions*** for the purpose of benchmarking. While the AER RIN definitions are the same, they fundamentally rely on using data based on different jurisdictional RAB values and rolled forward differently over time.

The AER has not taken into account the differences in approach used to allocate the RAB for the economic benchmarking RIN. These differences may lead to inaccurate conclusions regarding the relative efficiency of the DNSPs due to inconsistent data inputs.

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[36] Fearon and Moran, *Privatising Victoria's Electricity Distribution*, [sourced: https://www.ipa.org.au/library/pfampriv.pdf]

b) Weather adjusted demand was estimated

The economic benchmarking RIN requests data on System Annual Maximum Demand adjusted for seasonal differences. Weather adjusted data was estimated by the DNSPs as they did not collect this data for their internal purposes and the request was inconsistent with previous definitions applied by the AER.

> *All actual data provided in the previous EDPR was raw maximum demand as defined in chapter 10 of the National Electricity Rules. To provide an estimate for the historical weather adjusted data, CitiPower used a ratio derived by the National Institute of Economic and Industry Research (NIEIR) and applied it to the summation of the non-coincident and coincident maximum demand at zone substation level.*
>
> *CitiPower, Economic Benchmarking RIN Basis of Preparation, page 101*

Examples of different approaches undertaken by the businesses to provide the weather adjusted system demand information include:

- **Essential Energy** records the peak loads on its zone substations on a seasonal basis rather than on a financial year basis.[37]
- **Ausgrid's** maximum demand for the financial year includes period 1st May – 30th June from the previous financial year. Ausgrid's winter season covers period 1st May – 31stAugust and Ausgrid believes it is impractical to divide the winter season across two financial years.[38]
- Where estimated historical weather adjusted data is provided, **CitiPower** used a ratio and applied it to the summation of the non-coincident and coincident maximum demand at the transmission connection point to provide the 10% POE (Probability of Exceedance) Level data.[39]

I consider the weather adjusted peak system demand data used by the AER does not meet the AEMC preconditions:

- the data is not ***long term reliable information*** as the DNSPs do not collect weather adjusted demand information and it was subsequently estimated for the purposes of the RIN request
- the data is not ***high quality*** because the weather adjusted was estimated by the majority of the DNSPs
- the data is not consistent ***time series data*** because as stated above, this information was not collected historically by the DNSPs
- the data is not based on ***consistent definitions*** for the purpose of benchmarking as different assumptions were made to derive estimates of this information.

The RIN request has failed to take into consideration the ability of the DNSPs to provide the requested information regarding weather adjusted system demand. As such assumptions were made to derive estimates of this information, the results of which could be misleading or unreliable.

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37 Essential Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 44.
38 Ausgrid, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 33.
39 CitiPower, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 111.

c) *Differences in vegetation management practices*

The information requested by the AER as part of the economic benchmarking RIN includes:

- the number of vegetation maintenance spans (urban and CBD, rural and total)
- the total number of spans
- the average vegetation maintenance span cycle (urban and CBD, rural)
- the average number of trees per vegetation maintenance span (urban and CBD, rural).

Most businesses found that the definitions of 'vegetation management activities' provided by the AER were unclear, deeming them unworkable. For example, Powercor stated that providing information on vegetation management at a span level inappropriate as different parts of a single span may be inspected in different cycles.[40]

> *CitiPower does not have specific cycles for areas but rather the interval for pruning action is based on the particular circumstances of each span and the code allocated indicates the number of years before intervention is expected to be required. This can be more than once per year or periods greater than 5 years.*
>
> *CitiPower, Economic Benchmarking RIN Basis of Preparation, p187*

The estimates for the number of urban/rural vegetation maintenance spans has been challenging for the businesses with most providing estimated data based on historic records and sampling techniques. Examples of different approaches undertaken by the DNSPs to provide the vegetation management information include:

- **AusNet Services** provided estimates based on a sample survey undertaken in 2009. Based on these sample results, a percentage of trees being maintained relative to spans was calculated. AusNet Services' estimates assumed that the average number of trees in urban vegetation maintenance spans is consistent with the average number of trees in rural vegetation maintenance spans as the random sample did not distinguish between urban and rural data. Additionally, it was assumed that the average number of trees per vegetation maintenance span is unchanged in each year.[41]
- **Powercor** provided estimates based on the expected work volumes recorded by contract inspectors including removal, trims and scrubs. Powercor acknowledged that this information is not subject to any verification process and may vary from the actual work carried out by cutting crews.[42]
- **Ausgrid's** historic vegetation management data contained spans cleared, and trees trimmed which provides a basis to calculate the defects per span maintained. It does not provide account for spans which did not require clearing but vegetation was in the vicinity of the network. This means that the number of

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40 CitiPower Powercor, *Submission to the AER on draft regulatory information notice for economic benchmarking*, 18 October 2013, page 13.

41 AusNet Services, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 34.

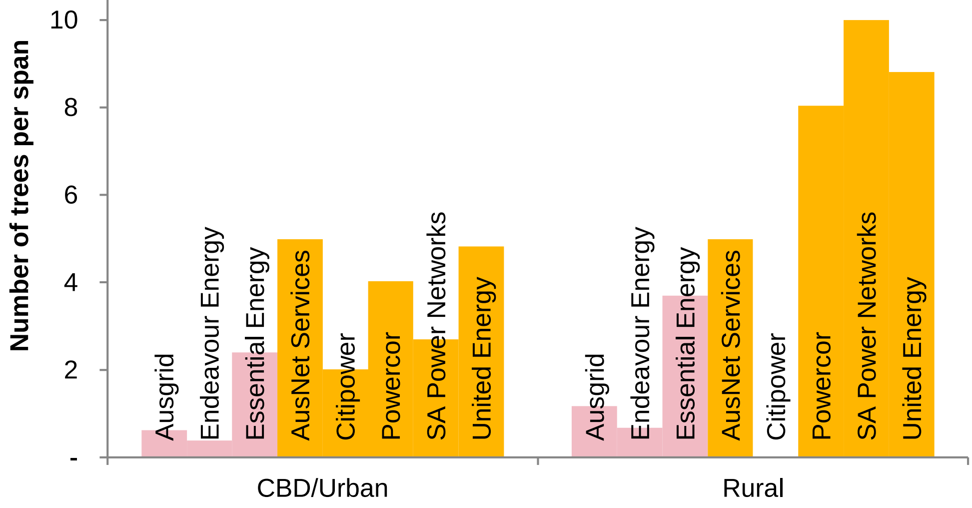
42 Powercor, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 194.

spans used in the calculation is significantly reduced inflating the number of defects per span.[43]

The differences in estimation techniques are evidenced by the inconsistent allocation between rural and urban vegetation management spans (see Figure 8). The number of trees per urban span in NSW is similar to the number of trees in the rural span. This is not the case for the Victorian and South Australian DNSPs, with large differences presented between the urban and rural vegetation maintenance spans as shown in Figure 8.

This example could be illustrative of the differences in span size, trees per span and tree density between the jurisdictions. These factors impact the expenditure incurred on vegetation management by each DNSP. As such, due to these variations, benchmarking which relies on this data is unreliable and potentially misleading.

Figure 8 – Number of trees per vegetation maintenance span (2013)



Source: Economic Benchmarking RIN templates

Powercor also acknowledged that the historic information provided was estimated based on current data. This was a significant limitation as the number of trees needing action within a span may change between cutting cycles where trees have different clearances and/or growth rates.[44]

Legislative differences in vegetation management practices between the jurisdictions are not appropriately reflected in the data templates.

In Victoria, the minimum clearance requirements are detailed in the Code of Practice for Electric Line Clearance contained within the *Electricity Safety (Electric Line Clearance) Regulations*. The clearance distances are calculated based on a range of criteria including whether the power line is in a high or low bushfire risk area, whether the power line is high or low voltage and the length of the section of power line between power poles.[45]

43 Ausgrid, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 62.
44 Powercor, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 194.
45 Energy Safe Victoria, *Power lines and vegetation management - A guide to rights and responsibilities*.

In NSW, the *Electricity Supply Act 1995* contains requirements for maintaining vegetation and powers of a DNSP to ensure it does not cause interference with electricity assets. The *Electricity Supply (General) Regulation 2001* deals with tree preservation and tree management plans associated with electricity works. Essential Energy's Vegetation Management Plan explains that many factors affect the extent of clearing including:

- the length of the span and conductor material
- the amount of sag on hot days with heavily loaded lines
- the amount of conductor swing
- the degree of whip of adjacent trees on a windy day
- the type of vegetation and its regrowth rate.[46]

Other circumstances also affect the vegetation management practices of DNSPS. For example, following the Black Saturday bushfires in 2009, the Victorian Government established the Victorian Bushfires Royal Commission to consider how bushfires can be better prevented and managed in the future. One of the recommendations from the Royal Commission was the replacement of all single-wire earth return (SWER) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk.[47] The replacement program was to be completed by DNSPs in areas of highest bushfire risk within 10 years and in areas of lower bushfire risk as the lines reach the end of their engineering lives.

Due to the Royal Commission's recommendations, Powercor and AusNet Services were required by Energy Safe Victoria to amend their Bushfire Mitigation Plans including their vegetation management and powerline replacement programs.[48]

The level of vegetation is also dependent on weather conditions, with different conditions experienced by each jurisdiction at any given time, e.g. due to drought or flood conditions. This makes any year-on-year comparison between the vegetation management expenditure incurred by DNSPs unreliable.

There are also jurisdictional differences in who is responsible for vegetation management. For example, in NSW the DNSPs are the party responsible for vegetation management49 while in Victoria this responsibility is shared between DNSPs and local councils.50 These differences affect the underlying expenditure incurred by each DNSP on vegetation management. Vegetation management expenditure was part of the opex reported in the RIN, and was used by the AER to provide a reduced level of opex to each of the three NSW DNSPs.

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46 Essential Energy, *Vegetation Management Plan*, June 2014 (issue 7).

47 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010, Recommendation 27.

48 Powercor Australia, *Pass Through Application: Costs arising from the Powerline Bushfire Safety Program*, 25 July 2014, page 6.

49 NSW Industry Safety Steering Committee, Guideline 3, *Managing Vegetation Near Powerlines*, October 2005.

50 Energy Safe Victoria, *Powerline and vegetation management - A guide to rights and responsibilities*, version 8, 2013.

I consider the vegetation management data used by the AER does not meet the AEMC preconditions:

- the data is not ***long term reliable information*** as there are significant differences in the vegetation management practices and regulatory obligations of the DNSPs
- the data is not ***high quality*** as there are differences in estimation techniques of terrain factors utilised by the DNSPs
- the data is not consistent ***time series data*** as there are a range of factors that impact the underlying vegetation management expenditure incurred by each DNSPs which are outside of their control and may have changed over time
- the data is not based on ***consistent definitions*** for the purpose of benchmarking as the DNSPs have not applied uniform assumptions and estimation techniques when reporting on terrain factors.

Due to the lack of consistency and accuracy of the data provided on terrain factors, vegetation management practices and environmental conditions this data input does not enable comparability of efficiency levels in vegetation management practices between DNSPs.

d) *Network length is subject to interpretation*

The economic benchmarking RIN requests information on circuit length and route line length. The AER's MTFP analysis measures productivity by constructing a ratio of outputs produced over inputs used. Route line length is a key output, while distribution and subtransmission line and cables, and transformers are key data inputs into the analysis.[51]

The AER has defined each of these inputs as follows:

- **Route line length** is the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. [52]
- **Circuit length** is calculated from the route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines.[53]

In order to be consistent with the AER's methodology and definitions, the DNSPs provided estimated information which required, in most cases, following data manipulation.

> *Route line length was calculated using Ausgrid's Geographical Information System (GIS) data. Ausgrid's GIS data is not represented as spans or singular routes, but represents the network as individual circuits; therefore significant manipulation of the existing data was required.*
>
> *Ausgrid, Economic Benchmarking RIN Basis of Preparation, p66*

The DNSPs also had considerable difficulty in providing historic information for these data inputs:

- An estimate of route line length was required as historical figures have not been reported and **Endeavour Energy's** GIS systems do not have audit trails or historical data readily available for this purpose.[54]
- For both overhead conductors and underground cables, **CitiPower** did not have data available for 2006-12 in the form specified, hence it was necessary to estimate/derive the requested historical data utilising other data source.[55]
- **AusNet Services'** route line lengths prior to 2013 were estimated based on historical circuit length data. Estimation is required because route line length data have not been previously recorded or reported. It is not possible to generate historic information on route line lengths from existing source systems. [56]

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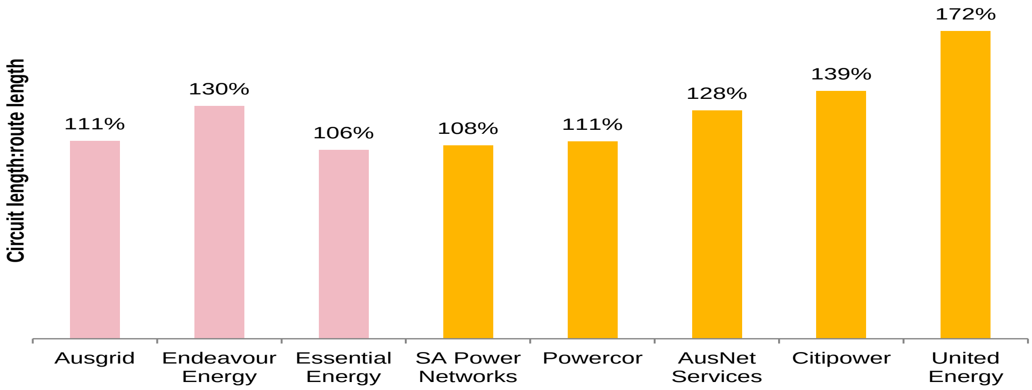
51 AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2014, page 28.
52 AER, *Economic benchmarking RIN for distribution network service providers*, Instructions and Definitions, November 2013, page 50.
53 AER, *Economic benchmarking RIN for distribution network service providers*, Instructions and Definitions, November 2013, page 32.
54 Essential Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 65.
55 CitiPower, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 210.
56 AusNet Services, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 36.

Figure 9 shows the circuit length across the businesses as a factor of route line length. The average circuit/route length index in NSW is 116 per cent while the Victorian and South Australian businesses reported an average of 132 per cent. This means that the circuit length is 32 per cent larger than the route line length in Victoria and South Australia, while only 16 per cent larger in NSW.

Figure 9 – Circuit length as compared to route length (2013)



Source: Economic Benchmarking RIN templates

The differences between the businesses (106 per cent for Essential Energy and 172 per cent for United Energy), partly due to the level of estimations and qualifications, illustrate that there could be errors in the data provided by the businesses. Further analysis needs to be undertaken by the AER regarding the accuracy of this data, prior to relying on this information for benchmarking purposes.

Endeavour Energy explains that a complex geospatial query was used to determine route line length for the network and the route length was reported once, regardless of whether there were multiple layers (transmission, high and low voltage) or a single layer.[57] Network length was an input to the scholastic frontier analysis, prepared by Economic Insights, to estimate the level of opex reductions for each of the three NSW DNSPs. The network length of each DNSP was also a key input to other benchmarking tools used by the AER.

I consider the network length data used by the AER does not meet the AEMC preconditions:

- the data is not ***long term reliable information*** as the network length information was estimated by the DNSPs in order to respond to the RIN request
- the data is not ***high quality*** and the accuracy of the data is unclear due to the levels of estimations and qualifications
- the data is not consistent ***time series data*** as the information was estimated using various modelling and data manipulation techniques
- the data is not based on ***consistent definitions*** for the purpose of benchmarking, as highlighted above the definitions as outlined by the AER led to data manipulation and estimation of the network length information.

The data inputs of route line length and circuit line length may not be internally consistent, and therefore may cause inaccuracy for benchmarking purposes.

57 Endeavour Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 65.

e) Cross ownership and related party arrangements

Electricity distribution assets in Victoria were geographically disaggregated into five distinct electricity distribution licences in 1994.[58] Over the last two decades ownership of these five businesses has changed numerous times, with various partnerships and associations characterising the ownership structure in Victoria.

In 2013, the Victorian electricity market was dominated by two parties as recognised by the AER:

- **Cheung Kong Infrastructure (CKI) and Power Assets** jointly have a 51 per cent stake in Powercor and CitiPower and a 200-year lease of the South Australian distribution network. The remaining 49 per cent of the two Victorian networks is held by Spark Infrastructure, a publicly listed infrastructure fund in which CKI has a direct interest.[59]
- **Singapore Power International** had a minority ownership in Jemena and part owns the United Energy distribution network. Singapore Power International also had a 51 per cent stake in SP AusNet (now AusNet Services), which owns Victoria's transmission network and the SP AusNet distribution network.[60]

In 2014, Singapore Power International contracted to sell a 60 per cent stake in Jemena, and a 20 per cent share in SP AusNet, to the State Grid Corporation of China. Subsequently SP AusNet was rebranded to AusNet Services as part of the transaction.

Figure 10 – Ownership and related parties arrangements in 2013

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[58] Victorian Government Gazette, Electricity Tariff Order, 30 June 1995 [http://gazette.slv.vic.gov.au/images/1995/V/P/4.pdf].

[59] AER, *State of the Energy Market*, 2013, page 60.

[60] AER, *State of the Energy Market*, 2013, page 60.

Historic related party arrangements[61] amongst Singapore Power-owned organisations are well documented[62] including:

- **Management services agreement** between Singapore Power subsidiary, SPIMS and AusNet Services
- **IT services agreements** between Enterprise Business Services (EBS), a subsidiary of SPIMS, Jemena and AusNet Services
- **Operating services agreements** between Jemena Asset Management (JAM), a wholly-owned subsidiary of SPI, AusNet Services, Jemena and United Energy.

Related party arrangements between CKI/Spark Infrastructure organisations include cost sharing arrangements between Powercor and CitiPower. The Cost Sharing Agreement entails an annual payment based on the pooling of defined overhead costs and the reallocation of those costs to each business based on a defined formula. The difference between the reallocation amount and the actual cost incurred by each business is the amount that is paid by one business to the other. There are no overheads, incentive payments, management fees or margins associated with the Cost Sharing Agreement.[63]

In 2005, a separate legal entity, CHED Services, was created and separated from Powercor and CitiPower to provide specialist corporate services under a Corporate Services Agreement Metering Services Agreement. CHED Services entered into an arm's length agreement with Powercor and CitiPower to provide these services from 1 January 2005 and continues to provide these services.[64]

Relevance to benchmarking

The cross ownership of these businesses and the potential for efficiencies due to related party arrangements is relevant to economic benchmarking. Powercor has outlined the benefits of these arrangements including:

- greater potential for the cost-efficient provision of network, telecommunication and back office services
- greater accountability for service cost and quality
- greater potential for improving service levels and performance
- greater focus on growth of the construction and field services and corporate services businesses by providing services to multiple clients.[65]

Pursuant to the *Energy Services Corporations Amendment (Distributor Efficiency) Legislation,* the three NSW DNSPs merged key elements under a common operating model including common executive roles and senior management. This took effect in 2013, and has no relevance to historic data provided under the economic benchmarking RIN. Also it should be noted that the NSW DNSPs do not have any significant related parties under the RIN. Related party arrangements affect the data provided by the DNSPs in the RIN, in particular the allocation of labour costs and

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61 The SPIMs and EBS agreements were terminated in March 2014.

62 SPI Electricity Pty Ltd, *Electricity Distribution Price Review 2011-2015,* Regulatory Proposal, November 2009.

63 Powercor, *Electricity Distribution Price Review 2011-2015*, Regulatory Proposal, November 2009. CitiPower, *Electricity Distribution Price Review 2011-2015*, Regulatory Proposal, November 2009.

64 Powercor, *Electricity Distribution Price Review 2011-2015*, Regulatory Proposal, November 2009.

65 Powercor, *Electricity Distribution Price Review 2011-2015*, Regulatory Proposal, November 2009, page 364.

overheads. This affected the AER's calculation of the opex efficiency score and the level of reductions to opex for each of the three NSW DNSPs.

I consider the data used by the AER does not meet the AEMC preconditions:

- the benchmarking data is not ***long term reliable information*** due to differing corporate structures and approaches for the allocation of costs of the DNSPs over the last decade
- the benchmarking data is not ***high quality*** as the differences in the treatment of related party arrangements has not been considered for benchmarking purposes
- the benchmarking data is not consistent ***time series data*** as changes to the corporate structure and related party arrangements over the last decade have not been considered for benchmarking purposes

Failure to take into account the related party arrangements and the allocation of costs could result in inaccurate benchmarking analysis.

f) Differences in cost allocation methods and capitalisation policies

Cost allocation methods and capitalisation policies impact the cost structures and expenditure of a business. The differences in the allocation of indirect costs should be taken into account when benchmarking the efficiency of the DNSPs.

The two approaches used by the DNSPs to allocate indirect costs include:

- Activity based costing approach – which identifies activities in an organisation and assigns the cost of each activity with resources to all products and services according to actual consumption by each. It should be noted that even within the activity based costing approach there are differing drivers and classifications across entities.
- Revenue (or RAB) based costing approach.

The cost allocation approach undertaken by each DNSP is summarised in Table 3.

Table 3– Allocation approach of indirect costs

DNSP	Cost allocation method
Ausgrid	Activity Based Costing approach
Essential Energy	Activity Based Costing approach
Endeavour Energy	Activity Based Costing approach
CitiPower	Indirect costs allocated using the value of the RAB, distribution revenue and customer numbers
Powercor	Indirect costs allocated using the value of the RAB, distribution revenue and customer numbers
United Energy	Weighted revenue average
AusNet Services	Activity Based Costing approach

Capitalisation policies and approaches also differ between the DNSPs and should be taken into account when benchmarking to ensure a 'like-for-like' comparison.

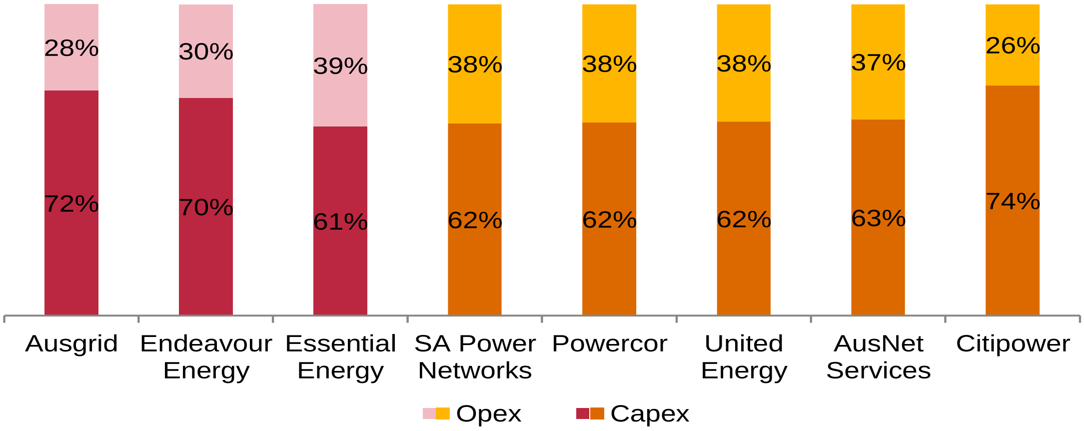
Accounting standards require capitalisation of overheads if they are "directly attributable", however this is judgemental and subject to an organisations' systems, processes and procedures. So two businesses could have the same approach e.g. corporate costs based on percentage of direct labour, yet still have differing outcomes due to the definition of the costs included in direct labour and corporate costs. For example:

- **Powercor** capitalises a portion of its corporate costs based on a percentage of direct costs rather than classifying these costs as operating expenditure. [66]
- The assessment of capitalised overheads is made on an activity or sub-activity basis according to the percentage of activity involved in the delivery of the **United Energy's** capital program.[67]

[66] Powercor, *Electricity Distribution Price Review 2011-2015*, Regulatory Proposal, November 2009, page 251.

A simple illustration of the impact of these differences in the capitalisation policies is the opex/capex split of the businesses (see Figure 11). While we have not had adequate time to undertake a quantitative impacts assessment, we believe there is enough to suggest that this data should not be used without further investigation.

Figure 11 – Opex/Capex split of the DNSPs (2013)



Source: Economic Benchmarking RIN templates and Category Analysis RIN templates

The capex/opex split between the businesses differs, ranging from 62% capex / 38% opex at SA Power Networks compared to 74% capex /26% opex at CitiPower. This could be due to a range of factors including the relative age of the networks, capitalisation policies and cost allocation approaches. If there is more capitalisation, the operating expenditure reported by the business will be lower. Cost allocation methodologies and capitalisation policies affect the data provided by the DNSPs in the RIN, in particular the allocation of labour costs and overheads. This affected the AER's calculation of the opex efficiency score and the level of reductions to opex for each of the three NSW DNSPs.

I consider the data used by the AER does not meet the AEMC preconditions:

- the benchmarking data is not ***long term reliable information*** as it was not provided on a like-for-like basis due to differences in capitalisation policies and approaches
- the benchmarking data is not ***high quality*** due to the different cost allocation approaches undertaken by the DNSPs which impact the cost structures and expenditure incurred
- the benchmarking data is not ***consistent time series data*** due to the differences in allocation of indirect costs over the last decade
- the benchmarking data is not based on ***consistent definitions*** for the purpose of benchmarking.

The differences in the allocation of indirect costs and the allocation between opex/capex should be taken into account when benchmarking the efficiency of the businesses.

[67] United Energy, *Electricity Distribution Price Review 2011-2015*, Regulatory Proposal, November 2009, page 99.

g) Differences in accounting methodologies and application of accounting standards

Three considerations have been identified in relation to accounting methodologies and the application of accounting standards including:

- differences in accounting methodologies
- inconsistent treatment of CPI
- changes to the reporting of historic financial information.

Differences in accounting methodologies

It is possible that differences exist across the benchmarked entities with respect to their accounting estimates and the timing of recognition of expenses. To the extent that differences exist it will create year-on-year volatility in the data inputs and the level of reported expenditure. For example, the capitalisation of borrowing costs which the three NSW DNSPs did pre-2009 would lead to lower expenses compared to a business that expensed borrowing costs when incurred, but higher costs when the capitalised costs were expensed in a later period. This would lead to a misleading comparison between two businesses with different treatment of borrowing costs.

Another example that could lead to a misleading comparison is the treatment of the provisions. There could be year-on-year volatility due to the differences between the recognition of accrual expenses and payments of employee entitlements between the DNSPs. Inconsistent treatment could led to the AER treating provision amounts and adjustments to their RABs in different ways meaning some DNSPs could be potentially adversely impacted.

Treatment of CPI

The AER's calculation of the total asset costs is equal to a return of capital for the indexed RAB balance and regulatory straight line depreciation which has been adjusted to include CPI. As illustrated in Appendix C, this approach overstates an assets' cost by 24 per cent for a $200m asset depreciated over a 45 year life. The difference arises from the failure to adjust for the CPI impact included in both the return of capital WACC adjustment and the regulator depreciation which also includes CPI. Therefore the higher an entities RAB the greater the overstatement of asset costs based on the AER's benchmarking calculation.

Reporting of historic data has changed

The DNSPs have outlined areas where providing historic data has been problematic including:

- **Powercor's** reporting specifications and templates have changed over the specified reporting period, so it was necessary to standardise historical reporting to more closely align with the requirements of the RIN.[68]
- In 2011, **United Energy** changed the manner in which Opex categories were reported to the AER compared to the 2006-2010 regulatory period. [69]

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68 Powercor, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 181.
69 United Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 11.

- In 2008, **Essential Energy** changed the way overheads were allocated from being based on direct labour to direct spend. As a result, 2006 – 2008 overheads have been backed out to be based on direct spend rather than direct labour.[70]

I consider the differences in accounting methodology used by the AER does not meet the AEMC preconditions:

- the data is not ***long term reliable information*** as the methodology for calculation of the asset cost base is inflated. I note however that respect to any differences in accounting practices such as estimates and the timing of transactions would be minimal over a long term
- the data is not ***high quality*** as the as the methodology for calculation of the asset cost base is inflated
- the data is not ***consistent time series*** data as the methodology for calculation of the asset cost base is inflated. I note however that respect to any differences in accounting practices such as estimates and the timing of transactions would be minimal over a long term but that there are likely to be differences at any one point in time
- the data is not based on ***consistent definitions*** for the purpose of benchmarking, as the methodology for calculation of the asset cost base is inflated which has the biggest impact on those DNSPs with the largest asset base.

70 Essential Energy, *Economic Benchmarking RIN Basis of Preparation*, April 2014, page 14.

h) Other issues for consideration

Following a review of the basis of preparation documents accompanying the economic benchmarking RIN templates, a list of differences between the businesses was identified. These differences were then rated based on their impact on the benchmarking results.

Issues with a rating of ***medium*** are summarised below.

Medium rating

- *Treatment of metering costs different depending on jurisdictional requirements*
- *The techniques used to estimate the service lives of various asset classes were different between the businesses*
- *Calculations of energy density and customer density were inconsistent between the businesses*

Issues with a rating of ***low*** collectively will cause a significant gap in the data inputs provided by the businesses in the NEM.

Low rating

- *Different approaches to the disaggregation of revenue into customer classes*
- *EBSS and STPIS revenue estimated*
- *Historic transformer capacity estimated*
- *Direct reconciliation of spatial and billing data not possible*
- *Age of the networks*
- *Service quality and reliability standards*
- *Energy fuel mix including gas and solar penetration*

Appendix A: Curriculum Vitae for Cassandra Michie

Cassandra Michie

Partner, Forensic Services

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Cassandra is a partner in the Sydney Forensic Services group and leads the forensic accounting team. Cassandra has over 25 years' experience in the public accounting profession and has led numerous financial investigations and preparation of expert reports in Australia, New Zealand, the USA (during a three-year secondment to New York with the Securities Litigation practice), Europe and Indonesia across all industries.

Relevant experience

Cassandra has a wide range of independent evidence based expert reports for electricity distribution and other government agencies and corporations. This has included

- Electricity and Gas, Jemena, preparation of multiple independent expert reports for JGN, JEN to the regulatory on cost allocation methodology and response to information requests
- Electricity, Veola, preparation of independent expert report to review calculations of cost allocation
- Electricity, ACTEW review of cost allocation methodology
- Electricity, Power and Water NT, analysis of accuracy of financial reporting
- Electricity, Essential Energy, Analysis of end of year revenue accrual calculation
- Investigator for Ausgrid, Essential Energy and Endeavour Energy across a range of matters
- Multiple NSW government entities and other corporate entities undertake cost accounting and cost allocation review including preparation of expert reports

Qualifications and affiliations

- Bachelor of Economics
- Bachelor of Commerce
- Bachelor of Laws
- Fellow Australian Chartered Accountant

Appendix B: Information relied on

Organisation	Documents
SA Power Networks	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, September 2012 (version 3)
Powercor Australia	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, January 2010 (version 0.7)
CitiPower	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, January 2010 (version 0.7)
AusNet Services	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, December 2010 (version 1.0)
United Energy Distribution	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, January 2011 (version 1.0)
Ausgrid	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, November 2013 (version 3)
Essential Energy	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, April 2014 (version 3)
Endeavour Energy	• Economic Benchmarking RIN - Financial and non-financial information (2006-13) • Economic Benchmarking RIN - Basis of Preparation (2006-13) • Annual Report • Cost Allocation Method, November 2013 (version 3)

Appendix C: Example of asset cost calculation

Opening RAB	$200.00
Life	45
Real depreciation	$4.44
CPI	2.50%
Nominal WACC	10.00%

Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Opening RAB		$200.00	$200.44	$200.79	$201.02	$201.14	$201.14	$201.01	$200.76	$200.36	$199.82	$199.12	$198.27	$197.25	$196.05	$194.68	$193.11	$191.34	$189.36	$187.16	$184.73
Inflation on RAB		$5.00	$5.01	$5.02	$5.03	$5.03	$5.03	$5.03	$5.02	$5.01	$5.00	$4.98	$4.96	$4.93	$4.90	$4.87	$4.83	$4.78	$4.73	$4.68	$4.62
Inflated RAB		$205.00	$205.46	$205.81	$206.05	$206.17	$206.17	$206.04	$205.77	$205.37	$204.81	$204.10	$203.23	$202.18	$200.96	$199.54	$197.93	$196.12	$194.09	$191.84	$189.35
SL depreciation		$4.56	$4.67	$4.79	$4.91	$5.03	$5.15	$5.28	$5.42	$5.55	$5.69	$5.83	$5.98	$6.13	$6.28	$6.44	$6.60	$6.76	$6.93	$7.11	$7.28
Closing RAB	$200.00	$200.44	$200.79	$201.02	$201.14	$201.14	$201.01	$200.76	$200.36	$199.82	$199.12	$198.27	$197.25	$196.05	$194.68	$193.11	$191.34	$189.36	$187.16	$184.73	$182.07

Year	NPV	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Return on capital	$189.05	$20.00	$20.04	$20.08	$20.10	$20.11	$20.11	$20.10	$20.08	$20.04	$19.98	$19.91	$19.83	$19.73	$19.61	$19.47	$19.31	$19.13	$18.94	$18.72	$18.47
SL depreciations	$58.21	$4.56	$4.67	$4.79	$4.91	$5.03	$5.15	$5.28	$5.42	$5.55	$5.69	$5.83	$5.98	$6.13	$6.28	$6.44	$6.60	$6.76	$6.93	$7.11	$7.28
subtotal	$247.26	$24.56	$24.71	$24.86	$25.01	$25.14	$25.27	$25.38	$25.49	$25.59	$25.67	$25.74	$25.80	$25.85	$25.89	$25.90	$25.91	$25.90	$25.87	$25.82	$25.76
Less: Inflation on RA	$47.26	$5.00	$5.01	$5.02	$5.03	$5.03	$5.03	$5.03	$5.02	$5.01	$5.00	$4.98	$4.96	$4.93	$4.90	$4.87	$4.83	$4.78	$4.73	$4.68	$4.62
Total	$200.00	$19.56	$19.70	$19.85	$19.98	$20.11	$20.24	$20.36	$20.47	$20.58	$20.68	$20.77	$20.85	$20.92	$20.98	$21.04	$21.08	$21.11	$21.13	$21.14	$21.14
	24%																				

21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
$182.07	$179.16	$175.98	$172.54	$168.81	$164.80	$160.47	$155.82	$150.85	$145.52	$139.84	$133.78	$127.33	$120.47	$113.19	$105.48	$97.30	$88.65	$79.51	$69.86	$59.67	$48.93	$37.61	$25.70	$13.17
$4.55	$4.48	$4.40	$4.31	$4.22	$4.12	$4.01	$3.90	$3.77	$3.64	$3.50	$3.34	$3.18	$3.01	$2.83	$2.64	$2.43	$2.22	$1.99	$1.75	$1.49	$1.22	$0.94	$0.64	$0.33
$186.62	$183.63	$180.38	$176.85	$173.03	$168.91	$164.48	$159.72	$154.62	$149.16	$143.33	$137.12	$130.51	$123.48	$116.02	$108.11	$99.73	$90.87	$81.50	$71.60	$61.16	$50.15	$38.55	$26.34	$13.50
$7.46	$7.65	$7.84	$8.04	$8.24	$8.45	$8.66	$8.87	$9.10	$9.32	$9.56	$9.79	$10.04	$10.29	$10.55	$10.81	$11.08	$11.36	$11.64	$11.93	$12.23	$12.54	$12.85	$13.17	$13.50
$179.16	$175.98	$172.54	$168.81	$164.80	$160.47	$155.82	$150.85	$145.52	$139.84	$133.78	$127.33	$120.47	$113.19	$105.48	$97.30	$88.65	$79.51	$69.86	$59.67	$48.93	$37.61	$25.70	$13.17	$0.00

21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
$18.21	$17.92	$17.60	$17.25	$16.88	$16.48	$16.05	$15.58	$15.08	$14.55	$13.98	$13.38	$12.73	$12.05	$11.32	$10.55	$9.73	$8.87	$7.95	$6.99	$5.97	$4.89	$3.76	$2.57	$1.32
$7.46	$7.65	$7.84	$8.04	$8.24	$8.45	$8.66	$8.87	$9.10	$9.32	$9.56	$9.79	$10.04	$10.29	$10.55	$10.81	$11.08	$11.36	$11.64	$11.93	$12.23	$12.54	$12.85	$13.17	$13.50
$25.67	$25.57	$25.44	$25.29	$25.12	$24.93	$24.70	$24.46	$24.18	$23.87	$23.54	$23.17	$22.77	$22.34	$21.87	$21.36	$20.81	$20.22	$19.59	$18.92	$18.20	$17.43	$16.61	$15.74	$14.82
$4.55	$4.48	$4.40	$4.31	$4.22	$4.12	$4.01	$3.90	$3.77	$3.64	$3.50	$3.34	$3.18	$3.01	$2.83	$2.64	$2.43	$2.22	$1.99	$1.75	$1.49	$1.22	$0.94	$0.64	$0.33
$21.12	$21.09	$21.04	$20.98	$20.90	$20.81	$20.69	$20.56	$20.41	$20.24	$20.04	$19.83	$19.59	$19.33	$19.04	$18.72	$18.38	$18.01	$17.61	$17.17	$16.71	$16.21	$15.67	$15.10	$14.49

Appendix D: Summary of Basis of Preparation for Economic Benchmarking

Revenue	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	Sourced from SAP Financials, Network Tariff Reports and Regulatory Accounting Statements. The S-Factor incentive amount reported for each year was taken from copies of Letters from ACC/AER confirming the financial incentive adjustment to apply for the financial year. The D-Factor incentive amount reported for each year was taken the final D-Factor Reports submitted to the regulator.	Sourced from the annual regulatory accounts. The respective financial years' reviewed WAPC has also been used to prorate the total revenue into the chargeable quantity and customer type line items. Data has been sourced from incentive scheme payment.	DUoS revenue information was extracted from the TM1 NUoS cube. Non-DUoS revenue information was extracted directly from previous audited Regulatory Accounts / RINs. D-Factor revenue allowances have been sourced from annual D-Factor submissions to IPART and the AER.	Sourced from Corporate Finance's annual tariff revenue report and checked against the annual regulatory accounting statements. Tariff Revenue data obtained from the annual regulatory accounts which contains actual billed revenue, accruals and billing adjustments.	Sourced from Corporate Finance's annual tariff revenue report and checked against the annual regulatory accounting statements. Tariff Revenue data obtained from the annual regulatory accounts which contains actual billed revenue, accruals and billing adjustments.	Regulatory Accounting Statements and the Annual RINs or the respective final decisions.	Information was sourced from Annual Regulatory Accounts, Annual Tariff Submissions & Post Tax Revenue Model The penalties or rewards from the STPIS or EBSS have been reported based on the year that the penalty or reward was applied, not the year in which it was earned.	• ESCOSA Price Returns • WAPC Pricing Returns • WAPC Pricing Proposals • WAPC Pricing Return • Regulatory Accounts
Estimation / assumptions	Actual information used. There is no estimated information for Revenue groupings by chargeable Quantities or by Customer Type or Class. Revenue (penalties) allowed (deducted) through incentive schemes has been completed as estimated information.	As the WAPC for each year was used to prorate the total revenue figures from the annual regulatory accounts into individual line items, the information is considered to be estimated.	While Endeavour made an assumption in order to ensure total DUoS revenue reported in table 2.1 and 2.2 reconciles to previous audited Regulatory Accounts / RINs it has not used Estimated Information.	Contains revenue split by tariff, then revenue billed for each tariff component. Revenue is then aggregated based on the chargeable quantities and customer class (customer class is based on the tariff).	Contains revenue split by tariff, then revenue billed for each tariff component. Revenue is then aggregated based on the chargeable quantities and customer class (customer class is based on the tariff).	Actual information provided.	In relation to STPIS, it has been assumed that STPIS Revenue was collected in accordance with the incentive scheme rate prescribed by the AER for the applicable period.	Actual information provided. Data is provided on as-billed or tariff applied basis.
Qualifications	There has been no material accounting changes during the financial periods 2005-06 to 2012-13 that has had an impact on Revenue.			Finance adjusts volumes and revenue according to accounting principles when there are known billing issues. Revenue from each component of distribution tariffs is not reported in the business systems. Therefore EBSS and STPIS revenue must be derived.	Finance adjusts volumes and revenue according to accounting principles when there are known billing issues. Revenue from each component of distribution tariffs is not reported in the business systems. Therefore EBSS and STPIS revenue must be derived.	Contains accrued data based on a quarterly billing cycle. This accrual is generated from the billing engine based on complex algorithms previously audited. S-factor values have been sourced from the AER's 2011 to 2015 final decision, appeal and change to Legislation.	Amounts included as 'Revenue from other Sources' relate to summer export payments made to customers for solar feed-in which forms part of DUOS Revenue reported in the Annual Regulatory Accounts.	Includes incentives/penalties recovered from customers within the tariffs for the applicable years as opposed to when earned/incurred from an accounting perspective. Estimations made for the following variables: EBSS, STPIS, Total revenue of incentive schemes.

OPEX	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	Sourced from SAP and TM1 and verified against Statutory Accounts and Regulatory financial statements.	Sourced from previous annual regulatory accounts and budgets, as well as workpapers used in preparation of the annual regulator returns (IPART/AER).	Sourced from TM1 (an OLAP tool) and included in the annual RIN Finance Statements for each year respectively.	Sourced from the SAP accounting system.	Sourced from the SAP accounting system.	The values in this table are actual and have been derived from the submitted data in the Annual Regulatory Accounts and the Annual RINs.	Using data extracted from the Annual Regulatory Accounts and information from the financial system.	Reported as part of allocated corporate costs (Corporate Affairs) in Regulatory Financial Reports submitted to ESCOSA
Estimation	Prepared in accordance with CAM and aligns to the Annual Reporting Requirements used in the FY2013 financial year. All financial data reported are actuals and can be verified in SAP.	Used estimated information for the proportion of costs relating to connection service activities that would be included as part of project type 11105 Non-Routine Meter Reading.	The information was transposed from the final Annual Financial Statements. The metering type 1-4 depreciation and capital expenditure for 2006 and 2007 was estimated.	Using the audited statutory accounts, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology.	Using the audited statutory accounts, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology.		Using data extracted from the Annual Regulatory Accounts and information from the financial system, operating expenses were allocated into the categories requested. In order to perform this allocation, all cost information was extracted from the financial system by cost ledger code.	Actuals are reported for: annual leave, workers compensation, income protection scheme, environmental (demolition and site restoration), employee bonuses, long service leave, self-insurance.
Qualifications	In 2011 there was a material change in the Annual Reporting Requirements from the AER. A FY2010 change in the integrated asset management system has resulted in generic costs being allocated to more direct categories. This has made it difficult for Ausgrid to backcast on the same basis as the FY2013 year.	In 2008/09, the Finance team changed the way overheads were allocated from being based on direct labour to direct spend. As a result, 2006-08 overheads have been backed out to be based on direct spend rather than direct labour.		An estimate is required for opex for network services as this is a product of standard control total opex less the estimated amount calculated as opex for transmission connection point planning.	An estimate is required for opex for network services as this is a product of standard control total opex less the estimated amount calculated as opex for transmission connection point planning.	Since 2011 there has been a change in the Opex categories under which costs have been reported to the AER compared to the 2006-2010. UE's cost allocation methodology however has not changed.	Overhead costs that cannot be directly allocated to a particular network are proportioned via a quarterly Activity Based Costing survey process completed by all cost centre managers and in accordance with the CAM.	All reported as actuals except for 'Network services movement in provisions'.
Provisions	Information provided is categorised as estimates as they are not readily available from either the annual financial statements, TM1 or SAP.	Estimated information for the regulated network business' share of movements through employee provisions and defined benefit superannuation liability, and the component of provision increases in the employee related provisions directly transferred to capital projects.	Provisions was extracted from the RIN for the relevant years, Balance Sheet and Capital working papers for the RIN data and the Movement in Provisions schedule used as part of the Annual Statutory Financial Statements.	Information presented utilises the cost allocation methodology applicable for the particular year and presents the data in alignment with the historical opex categories for that particular year.	Information presented in this table utilises the cost allocation methodology applicable for the particular year and presents the data in alignment with the historical opex categories for that particular year.	The opex provisions represented in the table are derived from the submitted data in the Annual Regulatory Accounts and the Annual RINs.	Provisions include: doubtful debts, uninsured losses, environmental provisions, license/regulatory fees, customer rebates.	

ASSETS	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	Sourced from the RFM and Fixed Asset Register. These provide the Opening Asset RAB values to the PTRM for the regulatory period being forecast, and therefore are based on actual expenditure information which is reconcilable to Annual Regulatory Accounts.	1. Regulatory capex working papers for each regulatory year 2. AER RFM for the period 2004-2009 3. The System assets FAR as at 30 June 2013. 4.Estimation of the average asset ages and standard lives.	Sourced from RFM as part of the final 2009 distribution determinations. For the later years the data is sourced from the RFM as party of Endeavour Energy's transitional regulatory proposal. Also sourced from FAR for asset value roll forward.	• RAB Financial Information for the period 2006-09 is sourced from the 2006-10 Final Determination RFM • RAB values have been based on capital expenditure consistent with that reported in Annual Financial RIN. • For replacement unit costs the 2010 Repex model for the 2011-15 price reset has been used	• RAB Financial Information for the period 2006-09 is sourced from the 2006-10 Final Determination RFM • RAB values have been based on capital expenditure consistent with that reported in Annual Financial RIN. • For replacement unit costs the 2010 Repex model for the 2011-15 price reset has been used	During 2011 EY prepared a report for UE on the valuation of specified assets for insurance purposes. The insurance valuation itemises UE's asset to a detailed asset class level. The assets lives are based on the same methodology used in the AER final decision for the 2011-15 pricing proposal.	AER Final Decision EDPR determination 2011–15 (RFM) The 'estimated service life of new assets' or 'weighted average life' of the asset group or category is completed using the total replacement cost as the weighting.	Roll Forward Model, for the 2005-10, adjusted where necessary to reflect the impacts of replacing forecast values with actual values.
Estimation / assumptions	Calculated the disaggregated RAB values by averaging the opening and closing values - allocated RAB data is estimated.	Most of the information is estimated, using the proportions derived from the 2013 FAR or data from the RFMs. Given that the RAB rolls forward from year to year, as soon as one year contains estimated data, the following year necessarily contains estimates.	No variables were assumed in the completion of this table for standard control services.	The business has estimated the Total Disaggregated RAB Asset Values as per AER's RIN I&D. The expected service lives for all assets are estimated from the standard asset lives of regulatory asset categories as per the EDPR determinations.	The business has estimated the Total Disaggregated RAB Asset Values as per AER's RIN I&D. The expected service lives for all assets are estimated from the standard asset lives of regulatory asset categories as per the EDPR determinations.		For the 2011-13 Regulatory Years, the 2010 information has been rolled-forward. Data on actual additions and disposals have been reconciled to the Annual Regulatory Accounts for the 2006-13 Regulatory Years.	Mostly estimated, except for disposals, and RAB roll forward variables related to easements and meters.
Qualifications	The asset lives for each category in each year were derived from the AER final decision RFMs from the 2004-09 and 2009-14 determinations Ausgrid has included the "Zone substations" share of transformers in its category.	A 2007 SKM valuation undertaken notes the RAB values are significantly lower than what the assets are worth. Essential Energy is in the process of cleaning up asset data in its system, namely, assigning assets of unknown age to a correct year of commissioning. This will necessarily impact on the residual remaining lives section of the data tables.	Endeavour Energy's methodology seeks to reflect the relative underlying service potential and the relative residual financial value of the RAB by apportioning actual RFM outcomes to actual fixed asset register information in line with the RIN RAB asset classes.		The business has no asset register that reconciles to the RAB information and therefore the AER's preferred method of estimating asset lives cannot be applied. The estimated residual service lives of the assets are therefore estimated as ratio of opening RAB to depreciation.	UE has relied on the EY report and the percentages in the table above to allocate the asset base for the 2006 to 2010 period and in accordance with the AER RIN I&Ds.	The RAB has been recorded in asset classes that do not allow a direct attribution into the AER's economic benchmarking RAB Asset classes for the majority of assets. Therefore, where direct attribution is not possible, the standard approach outlined in the RIN I&Ds has been used.	

OPERATIONAL DATA	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	**Energy delivered** - sourced from SAP via the Business Warehouse which collates customer volume consumption for billing purposes. **Energy received** – sourced from the BSP system and SAP Business Warehouse. **Customer class** breakdown is sourced from SAP **Location based breakdown** sourced from Ausgrid’s Outage Management System (OMS). **System demand data** obtained from Spatial Demand Forecast System. **Power factor data** sourced from SCADA, SAS and low voltage power quality information. All load data is obtained from the SCADA system or metering points. All weather data is obtained from Bureau of Meteorology weather stations.	**Total energy delivered** sourced from the annual regulatory accounts. Data from the respective financial years audited WAPC used to prorate the total energy delivered into the required categories. **Customer numbers** – extracted from the billing system, PowerOn Fusion and an Access database. **System demand** the vast majority of zone substation data was sourced from demand meters and from SCADA.	The information was extracted from the TM1 NUoS cube which is used by Endeavour Energy to store and report billed, accrued and import data related to energy volumes, customer numbers and demand KW/kVA and calculate associated revenue outcomes at the network tariff level. Network Load History Database, Summer Demand Forecast 2014-23 & 2012-21, Winter Demand Forecast 2013-22. Information used to calculate unmetered customer numbers was extracted from a monthly report provided to the default retailer in Endeavour Energy’s network area.	**Energy delivered** - obtained from billed energy volumes, accruals and any billing adjustments for that given year. Billed energy volumes, accruals and billing adjustments is calculated at site (NMI) level and aggregated as a total. **Customer numbers** – obtained from Corporate Finance’s end of year reports which are sourced from the billing system, where NMIs are classed as ‘Active’. **System demand** - All zone substation raw peak demand source data is collected from Ion power quality meters, located at each individual zone substation.	**Energy delivered** - obtained from billed energy volumes, accruals and any billing adjustments for that given year. Billed energy volumes, accruals and billing adjustments is calculated at site (NMI) level and aggregated as a total. **Customer numbers** – obtained from Corporate Finance’s end of year reports which are sourced from the billing system, where NMIs are classed as ‘Active’. **System demand** - All zone substation raw peak demand source data is collected from Ion power quality meters, located at each individual zone substation.	**Total energy delivered** based on actual data sourced from the annual Regulatory Accounts and RINs. Actual data sourced straight from CIS/SAP Billing System Data. This information is derived at the time of reporting from the Q-report which is extracted from CIS and SAP. **Customer numbers** – CIS/SAP Billing System and ESC compliance submissions. **System demand** - Actual data sourced from the Interval Metering System.	**Energy delivered** - sourced from the Annual Regulatory Accounts, Tariff Quantity Schedules extracted directly from the billing system Tariff Quantity Schedules (included in Annual Regulatory Accounts and Tariff Submissions). **System demand** - For the 2006-09 Regulatory Years, sourced from historic SCADA extracts contained in spreadsheets. For 2010-13, data was extracted from OSI Pi and SCADA.	• ESCOSA Price Returns • WAPC Pricing Return • AEMO Settlement data acquired through SAPN's NESS system • Energy data available from ElectraNet • Data available from embedded generators • PV approved capacity & NESS
Estimation / Assumptions	Actual information could not be provided for all data points because in the process of extracting data from the OMS reporting environment for use in completing this Notice, it was identified that some historical outage event records contained incorrect customer allocations.	Customer numbers prior to November 2012 did not include de-energised NMIs. The de-energised numbers from 2012/13 have been prorated across the previous years. • Peak: 7am-9am and 5pm-8pm • Shoulder: 9am-5pm and 8pm-10pm • Off peak: all other times.	For non-coincident demand, the peak for each substation may not be the actual system peak recorded in the financial year. It is the peak recorded in the season that the system peak occurred. The power factors of the Endeavour Energy network are used in the conversion of MVA at the zone and high voltage customer level. Low voltage power factor was estimated. The number of de-energised customers was estimated.	CitiPower does not hold historical data in regards to the status of the NMI therefore an estimate of de-energised NMIs were obtained from 2013’s end of year position. The estimated number of (1% of de-energised sites) was then added on to the average year end customer numbers. It is not possible to reconcile GIS (spatial data) and CIS (billing data) exactly, therefore a weighted average is applied to determine customer type by location.	Powercor does not hold historical data in regards to the status of the NMI therefore an estimate of de-energised NMIs were obtained from 2013’s end of year position. The estimated number of (1% of de-energised sites) was then added on to the average year end customer numbers . It is not possible to reconcile GIS (spatial data) and CIS (billing data) exactly, therefore a weighted average is applied to determine customer type by location.	• For 2011-13 the data is as per the annual RIN. • For 2009-10 it is as per the ESC compliance submissions. • From 2006-08 it is as per what has been reported in the EDPR 2011 RIN submission	Average power factor conversion for SWER lines was estimated based on 2014 data from the SCADA system. 2014 data is considered more accurate and complete than the available 2013 information and is considered the best estimate of the information required	• Total energy delivered • Energy Delivery at On-peak times • Energy Delivery at Off-peak times • Controlled load energy deliveries • Energy Delivery to unmetered supplies Energy into DNSP network • Residential customer numbers • LV and HV demand tariff customer numbers • Unmetered Customer Numbers
Qualifications	Data for High Voltage Customers connected at 132kV is not readily available for years 2006-10. Where data was missing for a HVC, the most recent available value was reported. Redbank 132kV generator has data missing for a number of seasons. Redbank 132kV generator was estimated to be 130MW of generation for all years where data was not recorded. This is the most recent value available and represents the best estimate for the generator output.	Essential Energy records the peak loads on its zone substations on a seasonal basis rather than on a financial year basis. For example: the values for summer 2011/12 and winter 2012 were used to provide the 2012 year data for this submission.	Variances in the TM1 NUoS cube and total customers reported in previous audited Regulatory Accounts / RINs were identified as immaterial.	CitiPower did not commence weather adjusting the non-coincident terminal station connection point maximum demands until 2011 and hence NIEIR ratios were used to estimate the non-coincident 10 and 50% POE values.	Powercor did not commence weather adjusting the non-coincident terminal station connection point maximum demands until 2011 and hence NIEIR ratios were used to estimate the non-coincident 10 and 50% POE values.			

PHYSICAL ASSETS	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	Sourced from Ausgrid's Geographical Information System (GIS) – the repository for spatial asset data and SAP PM. Some data is sourced from the 'Sincal' modelling tool used by the Distribution Planning section. Other data is sourced from 'RIC' the Ratings and Impedance Calculator, which in turn sources its data from GIS and SAP PM (Plant Maintenance).	Figures for 2006-07 sourced from annual ESAA reports. Figures for 2008-10 were sourced from annual Network Performance Reports (NPR). **Transformer capacity** - Data has been sourced from the WASP database using SQL and grouping of data in Excel.	Estimated data, based on samples of conductor lengths and characteristics. Circuit lengths sourced from ESAA reports and the Network Characteristics database. Transformer capacities variables sourced from historical end of financial year Cognos reports (Ellipse).	GIS is the originating data source. However, since GIS records are not continuously archived, for previous years' data it was necessary to refer to historical reports that provided consolidated overhead line length information. The data source for the estimated overhead and underground network weighted average MVA capacity come from estimates provided by the AER.	GIS is the originating data source. However, since GIS records are not continuously archived, for previous years' data it was necessary to refer to historical reports that provided consolidated overhead line length information. The data source for the estimated overhead and underground network weighted average MVA capacity come from estimates provided by the AER.	The data has been sourced from UE's Geographical information System from the AM/FM reports and Demand Management System.	For regulatory years 2006, 2008 and 2010 to 2013, data was directly extracted from internal periodic system reports (from the Asset Management System (SDME)).	• GIS • Transformer capacity records • Network Planning 66kV and 33kV line spreadsheets • Internal records • ESCOSA Price Returns • WAPC Pricing Proposals • Network Planning Asset Utilisation Spreadsheets • Network Planning Asset Utilisation Spreadsheets
Estimations / Assumptions	**Distribution transformer capacity** is sourced from data underlying Ausgrid's previous responses to the Energy Supply Association of Australia's (ESAA) Distribution sector benchmarking survey, with the exception of 2009 where the data could not be located. **Public lighting poles:** 2006-2012 poles used solely for public lighting were estimated as these were not identified prior to 2012.	Essential Energy has used estimated information when there is no 'Date Constructed' for the Substation Site or asset movement date for the Transformer (in the case of Transformers in Stores). Estimates are also used for length of low voltage lines and weighted average MVA capacity e.g. sub transmission feeder ratings etc.	**Subtransmission Mains:** were determined for 2008-09 and 2012-13 and provided by ANP, based on the Network Characteristics file for identified individual feeders. HVC customer capacity figures were estimated by determining maximum demand (kWh) values for each Financial Year period, from historically available metering data.	Since no originating source data was available, it was necessary to estimate/derive the requested historical data utilising other data sources, in this case the Annual Regulatory Performance Reports.	Since no originating source data was available, it was necessary to estimate/derive the requested historical data utilising other data sources, in this case the Annual Regulatory Performance Reports.	UE does not own 33klv and 132kv lines. Unless otherwise stated, the data for the years 2007-2013 is actual, and 2006 is an estimate, with the key assumption in the estimate being that the data used (2005 and 2007 data) is reasonable enough to provide an approximation for 2006.	Internal reports (from the Asset Management System) for the 2007 and 2009 Regulatory Years are not available and cannot be generated as the system is live.	Actuals are only reported where the variables are not applicable to SAPN. All variables are estimates except for Cold spare capacity .
Qualifications	Data is not generally extracted, so for this request has had to come from a variety of sources. Information for 2006-07 has come from old spares holdings spreadsheets. 2011 values have come from a spares analysis undertaken in that timeframe. 2012 and 2013 figures have come from SAP PM extractions done for the ESAA's Distribution sector benchmarking survey. 2008 to 2010 figures were required to be estimated as no data for this period could be located. Datasets used in the calculation for circuit capacity for the 2013 regulatory year were not available for other years. Given the assumptions made in the compilation of this data for the 2013 regulatory year, and the levels of error incurred on the dataset in the application of these assumptions, it is considered a best estimate to assume that the overall weighted average MVA for each variable is relatively constant. As such the years prior to 2013 have been backcast with the same value as calculated for 2013	The quality of the information stored in the GIS has been steadily increasing over time. Issues with data accuracy in GIS: On-going data capture exercises have steadily increased the population of Essential Energy electricity assets recorded in the GIS. The reliability of the data for 2011-13 is dependent on the accuracy of the data within the WASP database at the time that the historical data was extracted as well as the accuracy of the assumptions and estimations that have been used. The reliability of the data for 2006-10 is dependent on the accuracy of the data for 2011-13 as well as the assumption that an annual 1% growth rate has occurred for the past 8 years.	Transmission Network Planning Reports are forward looking recommendations, contain out-dated Single Line Diagrams (SLD) in several cases and therefore were not considered accurate for this reporting. The total zone substation capacity at DPA0604 has been reported as required by the RIN instructions as the sum of DPA0601, DPA0602, DPA0603 and DPA0605. This total is not the zone substation capacity, but includes subtransmission capacity, where two step transformation is involved.	The available data for 2006-10 was not in the form specified in this Information Notice. Since no originating source data was available, it was necessary to estimate/ derive the requested historical data utilising other data sources, in this case the Annual Regulatory Performance Reports.	The available data for 2006-10 was not in the form specified in this Information Notice. Since no originating source data was available, it was necessary to estimate/derive the requested historical data utilising other data sources, in this case the Annual Regulatory Performance Reports. On review the data reported for this year indicated a significant increase in total distribution transformer capacity and inconsistent to all other years. Hence it is assumed that the reported data for this year was incorrect. The original data of 5,613 MVA which was reported to the AER as per the Annual Regulatory Performance Reporting, was amended to 5,261 MVA using a simple linear regression of data provided for other years.	Unless otherwise stated, the data for the years 2007-2013 is actual, and 2006 is an estimate, with the key assumption in the estimate being that the data used is reasonable enough to provide an approximation for 2006. UE does not own cold spare capacity and information relating to customer owned HV transformers.	The information provided is considered 'actual information' as it was extracted from the system, however it is noted that the system data has been subject to data cleansing over the Regulatory Years. This preparation method will systematically underestimate the capacity for earlier years as any assets that have been removed between 2013 and the start date of the report (2003) will not be included in the total capacity for the earlier Regulatory Years.	

QUALITY OF SERVICE	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	Sourced from outage event records located in Ausgrid's Outage Management System (OMS) and its related reporting environment. Data for 2006-07 has been taken from the OMS reporting environment, however; the data for these years originated from Ausgrid's legacy Network Reliability Data (NRD) system. Capacity utilisation data also comes from RIN tables, SAP, SINCAL.	Data is sourced from PowerOn Fusion and Distribution Management and Outage Management Systems (DMS/OMS). Data has been sourced from reported Planned customer minute off-supply and Unplanned customer minutes off-supply.	Data sourced from System Fault Recording database (SFR) and Outage Management System (OMS) **Energy not supplied - Unplanned –** SFR and OMS customer minutes off supply used to calculate unplanned SAIDI. **Energy not supplied - Planned –** Customer minutes off supply used to calculate Planned SAIDI for internal management reporting and the Electricity Network Performance Reports.	Source includes annual Regulatory Performance Reports and the AER Annual RINs The originating sources are: • Years 2006 to mid-2008 inclusive Outage Management System & Business Objects • Years mid-2008 to 2013 inclusive Outage Management System & Business Intelligence • AER outage exclusions as per the AER STPIS Scheme dated November 2009	Source includes annual Regulatory Performance Reports and the AER Annual RINs The originating sources are: • Years 2006 to mid-2008 inclusive Outage Management System & Business Objects • Years mid-2008 to 2013 inclusive Outage Management System & Business Intelligence • AER outage exclusions as per the AER STPIS Scheme dated November 2009	Annual feeder reliability data demand figures are obtained from the DMS. UE has sourced the information to complete these tables from the Distribution Loss Factors reports submitted to the AER.	The reported values of energy not supplied were obtained from the AER Annual RIN Reports (2011 – 2013), the Annual Electricity Performance Reports (2006 – 2010) and the Outage Management System.	CIS/OV (i.e. customer meter readings), GIS and OMS Data provided is based on SAPN methodology and represents audited actuals as reported to AER and AEMO for the period 2006-20012. An unaudited value has been included for 2012/13.
Estimation / assumptions	Estimated information for 2006-07, based upon actual outage event records but adjusted appropriately to account for the step change. Number of Customers Interrupted (CI) and Customer Minutes Interrupted (CMI) was estimated. Estimates were also provided for customer allocations for 2006-2011. Previous to regulatory year 2012, Ausgrid did not enter all planned outage data into the OMS system, therefore making reporting against individual NMIs as required in this section impossible and requiring estimates.	Based on the information available the estimated kWh were determined by calculating an average kWh use per minute for each financial year, based on the total consumption divided by the total number of customers divided by the number of minutes in a year.	The accuracy of customer numbers and its impact on SAIDI has been the subject of an AER audit and recent IT projects have been completed to rectify the identified errors. The errors cannot be removed from historical and are therefore likely to have some impact on the reported SAIDI/ SAIFI information.	The individual feeder total aggregated annual energy consumed is used together with the planned & unplanned supply duration parameters exclusive of the excluded outages as specified in this Information Notice. Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions.	The individual feeder total aggregated annual energy consumed is used together with the planned & unplanned supply duration parameters exclusive of the excluded outages as specified in this Information Notice. Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions.	As UE does not have the historical data on customer demand, the data for energy not supplied was based on the annual reports submitted to the regulator Additionally, Major Event Days (MEDs) were not required in the annual regulatory reports prior to calendar year 2011 and no threshold existed. Hence for the years 2006-2010, as per the AER's RIN I&D the 2012 Threshold has been applied.	System losses are the proportion of energy that is lost in the distribution of electricity from the transmission network to customers. It has been calculated as the difference between electricity imported and electricity delivered as a percentage of electricity imported.	Where an interruption affects a phase(s), the number of customers affected is estimated as follows: 1/3rd if only one LV phase is affected, 2/3rds if two LV phases are affected and 2/3rds if only one HV phase is affected. Data provided is based on SAPN methodology and represents audited actuals as reported to AER and AEMO for the period 2006-20012. An unaudited value has been included for 2012/13.
Qualifications	This information is estimated by Ausgrid because a large number of input variables were utilised in the calculation methodology. A small number of these variables were required to be estimated due to missing data. Unless specifically mentioned in the methodology, the information provided is actual data. Both throughput and exit capacity data was limited for some regulatory years. If data was missing or deemed erroneous for a particular zone substation listing then the next available annual capacity values were used.		Unable to fully comply with any of the methods prescribed by the AER in the Economic Benchmarking RIN. The accuracy of customer numbers and its impact on SAIDI has been the subject of an AER audit and recent IT projects have been completed to rectify the identified errors. The errors cannot be removed from historical and are therefore likely to have some impact on the reported SAIDI/ SAIFI information.	The energy not supplied was determined using the third method utilising customer consumption aggregated at the feeder level in place of the billing data.	The energy not supplied was determined using the third method utilising customer consumption aggregated at the feeder level in place of the billing data.		Electricity imported is the total electricity inflow into the distribution network (including from Embedded Generation) less the total electricity outflow into the networks of the adjacent connected distribution network service providers or the transmission network. Electricity delivered is the amount of electricity transported out of the network to customers as metered (or otherwise calculated) at the customer's connection.	The value excludes the loads seen by the second step transformations to avoid double counting of the loads seen by the first and second step transformations. As an exercise, SAPN re-calculated the utilisation values which would have been seen had these loads been included and found that on average, the utilisation values would have increased by 1% per annum.

OPERATING ENVIRONMENT	AUSGRID	ESSENTIAL	ENDEAVOUR	CITIPOWER	POWERCOR	UNITED ENERGY	AUSNET	SA POWER NET
Source of info	**Customer density** - number of customers divided by route length of network in KM **Terrain** - total Number of Spans was calculated using GIS data **Route Line Length** calculated using GIS data **Weather stations:** Bureau of Meteorology list	**Terrain factors:** WASP system, Vegetation Cost Model, Field survey 2011/12, Smallworld system Figures for the overhead route length for 2006-09 were obtained by determining the ratio of overhead route length to overhead circuit length for years 2010-13, finding the average and applying that average to the overhead circuit length. GIS is also used for circuit/route line lengths.	Sourced from GIS, Rural Fire Service map polygons applied to the GIS, a Scope and Audit review of vegetation management contracts using the work flow management system, the Bureau of Meteorology web site and the Vegetation Program Completion Process.	**Density factors** - There is no source for these variables as they are ratios derived from variables already in the Benchmarking RIN. **Terrain factors** - For the year 2013 GIS was the originating data source (i.e. from where the data is obtained) – this was the first time that this metric has been reported in this manner. Hence, there is no source data available for the years 2006-12 inclusive. **Service factor** - With respect to Overhead Conductors, GIS was the originating data source.	**Density factors** - There is no source for these variables as they are ratios derived from variables already in the Benchmarking RIN. **Terrain factors** - For the year 2013 GIS was the originating data source (i.e. from where the data is obtained) – this was the first time that this metric has been reported in this manner. Hence, there is no source data available for the years 2006-12 inclusive. **Service factor** - With respect to Overhead Conductors, GIS was the originating data source.	Information sourced from the GIS database the VEMCO Vegetation Management System (VMS) database **Terrain** - In previous years (2009-12) actual information was not available, so has been estimated using the change in route length percentage. **Service factor** - For the years 2006-12 the data is an estimate. It is has been estimated based on the percentage movement of overhead circuit line length from one year to the next. This estimate is used because route line length is the distance of overhead lines between two poles.	Information was sourced from prior year annual AER Reliability Performance Reports and the Asset Management System. Using historical line length data in Annual Performance Reports and Vegetation Management system and plan.	• GIS circuit length data • Vegetation clearance contractors • Based on route length and average span length per base voltage level. • Local Network Records • Vegetation clearance contractors estimate • Bureau of Meteorology website
Estimations / Assumptions	The original definition of Route Line Length to be “measured as the length of each span between poles and/or towers” is not relevant to underground cables; therefore length for each underground conductor circuit was added to the overhead route line length which was calculated in accordance with the original definition. That is; “each span is considered only once irrespective of how many circuits it contains”.	The FME Workbench used to determine the route length of underground cables was unable to resolve cables in parallel which had the same voltage. If the Workbench could resolve this issue then the total route length would be less, but it would be extremely difficult to estimate. In addition, due to the way in which underground data has been captured in the GIS and the tolerance that was used, there would be instances where cables have been inadvertently deemed as sharing a trench and others that have been inadvertently missed.	It is assumed the ratio of route line to circuit line length has been constant over time, back to financial year 2005/06.	**Customer density** has been calculated as the total number of customers divided by the route Line Length of the network **Energy Density** has been calculated as the total MWh divided by the total number of customers of the network. **Demand Density** has been calculated as the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network.	**Customer density** has been calculated as the total number of customers divided by the route Line Length of the network. **Energy Density** has been calculated as the total MWh divided by the total number of customers of the network. **Demand Density** has been calculated as the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network.	Demand, customer and energy density do not need any additional information and can be calculated using information available in other categories.	Information was sourced from prior year annual AER Reliability Performance Reports and the Asset Management System. Route line lengths prior to 2013 were estimated based on historical circuit length data. The estimation was derived by calculating the ratio of route line length to circuit length for 2013.	Assumed that rural proportion for line length is the same as rural proportion for circuit length for rural proportion and there are two defects assumed per span in NBFRA for Total vegetation maintenance spans. Assumes 2 defects per Span as do not collect information.
Qualifications	Ausgrid assessed the AER’s recommendation to use number of poles minus one to calculate the number of spans. Further analysis found this methodology to be fundamentally flawed where the overhead network was not linear in nature. Ausgrid utilised LiDAR acquired data for 2012 and 2013 to calculate vegetation within the vicinity of its network covered by vegetation management activities.	Actual GIS data was not available for 2006 to 2010; therefore an estimate was used as described above.	All information provided for service factor areas is not readily available in historical data, audit records, or captured.	With respect to Overhead Conductors - no modelling was necessary; the data was obtained utilising a GIS query that summates the total of the overhead span lengths to determine the route line length. Rural for CitiPower is zero.	With respect to Overhead Conductors no modelling was necessary; the data was obtained utilising a GIS query that summates the total of the overhead span lengths to determine the route line length. These variables ratios and are therefore dependent upon whether the variable used in the ratio is an actual figure or an estimate. As at least one variable is an estimate, this ratio has been considered as an estimate.	In previous years (2009-12) actual information was not available, so has been estimated using the change in route length percentage.	It has been assumed that high bushfire risk maintenance spans are equal to the number of Bushfire risk spans in the Vegetation Management System.	Route line length for 2013 based on estimate of percentage of route for each voltage that runs parallel to other voltages. Conductor on the same route was estimated by voltage starting with LV and working up to 132kV. Estimate of route line length for earlier years has been pro-rated by historical GIS circuit length data.