



Better regulation
Explanatory statement

**Regulatory information notices to collect
information for economic benchmarking**

November 2013

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Shortened forms

Shortened term	Full title
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AUCC	Annual User Cost of Capital
BOM	Bureau of Meteorology
CAM	Cost allocation method
CPI	Consumer price index
DNSP	Distribution network service provider
EBSS	Efficiency benefit sharing scheme
EFA	Expenditure forecast assessment
ENA	Energy Networks Association
MED	Major event day
MVA	Megavolt ampere
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network service provider
RAB	Regulatory asset base
RIN	Regulatory information notice
RIO	Regulatory information order
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
STPIS	Service target performance incentive scheme
TFP	Total factor productivity
TNSP	Transmission network service provider
TOU	Time of use

Summary

The Australian Energy Regulator (AER) is undertaking the Better Regulation program of work to deliver an improved regulatory framework, which focuses on promoting the long term interests of electricity consumers. As part of this program, we will release the Expenditure Forecast Assessment Guidelines (Guidelines) on 29 November 2013. The Guidelines set out the assessment approaches we will undertake to determine efficient expenditure allowances and the information we require from businesses to do so. As part of the process of developing the Guidelines, we have taken the opportunity to review and improve our approach to assessing expenditure. In doing so, we have developed new benchmarking techniques that we intend to use in conjunction with our existing assessment techniques to inform our assessment of NSPs' proposed expenditure.

The new benchmarking techniques are category analysis and economic benchmarking. Category analysis will allow us to benchmark expenditure at the disaggregated category level. Economic benchmarking will allow us to analyse the efficiency of network service providers (NSPs) over time and compared to their peers. Economic benchmarking will also assist us to develop a top down forecast of expenditure and estimate productivity change.

The regulatory information notices (RINs) set out in the attachments to this statement relate specifically to economic benchmarking. The data requirements for category analysis are different from those in economic benchmarking and set out in a separate RIN consultation process.¹

In order to conduct economic benchmarking we have developed RINs to collect the requisite information from NSPs. This includes a historical data set that will allow us to provide the public with consistent, transparent data. This will form the basis for one aspect of our first benchmarking report in September 2014. We will also use it to assess benchmark operating expenditure (opex) and benchmark capital expenditure (capex) that would be incurred by an efficient NSP as required by the National Electricity Rules (NER). Going forward, we will continue to require NSPs to report this data annually so that interested parties can conduct their own analysis and modelling.

We have consulted extensively with stakeholders in relation to both the Guidelines and the techniques and data requirements for economic benchmarking. Following the publication of our issues paper in December 2012, we conducted seven economic benchmarking workshops between March and June 2013. We have sought comments from interested parties in response to preliminary RIN templates that we provided to stakeholders in July 2013 and again in August 2013. We subsequently issued draft economic benchmarking RINs in September and held further bilateral meetings and a workshop on auditing requirements and other information requirements in October 2013.

We received a number of submissions on the draft RIN and templates. While some submissions commented on particular economic benchmarking variables, they did not raise issues with the key economic benchmarking parameters. Rather, submissions generally focussed on the manner in which NSPs would provide the information to the AER. This included the number of years of back cast data, assurance requirements, the ability to provide data and the form of the statutory declaration on the accuracy of the data.

This explanatory statement outlines our changes to the draft RIN in light of submissions. Some key changes include:

¹ Detailed information and documentation on economic benchmarking and category analysis are available on our website at <http://www.aer.gov.au/node/21843>.

- an eight year back cast data set (reduced from ten years)
- audit requirements for five years of information (reduced from ten years)
- separate, comprehensive instructions for completing the RIN Responses.

The RINs require each NSP to provide us with unaudited RIN Responses at the beginning of March 2014. We will use this information to conduct internal testing and validation to identify anomalies and issues in the information we receive from NSPs in response to the RINs. Where these are identified we will work with NSPs and aim to resolve these issues prior to the submission of audited RIN responses.

NSPs are required to submit audited RIN responses, which must be certified by the NSP's chief executive officer on 30 April 2014. Once these RIN responses have been received we will publish them. This will initiate our public consultation on the application of economic benchmarking techniques as we will seek submissions on this data. The specifics of this consultation will depend on the quality of the data provided in response to the RIN. We will set out more precise timings for this process once we have received the completed RIN responses.

Ultimately, we intend to release the findings of our economic benchmarking analysis in the issues papers for the resets for NSW/ACT distribution network service providers (DNSPs), Transend and Transgrid. These issues papers are due to be released in July 2014. This will allow these NSPs to comment on the findings of our economic benchmarking analysis in advance of our draft determinations for these resets. We will also publish the results of our economic benchmarking analysis in our first benchmarking report in September 2014.

Next steps

A summary of the key indicative dates for economic benchmarking is as follows.

Date	Milestone
3 March 2014	Unaudited RIN responses (for back cast data) set due
March 2014	Data checking/ validation process commences
30 April 2014	Audited and certified RIN responses (for back cast data) set due
May 2014	Publicly release data and seek cross submissions
July 2014	Economic benchmarking models finalised, results of models included in issues papers as part of revenue reset processes
September 2014	Results of economic benchmarking models included in annual benchmarking report

Going forward, we will continue to require NSPs to report this data annually. The most recent regulatory year's audited data is due on:

- 30 April for NSPs with a regulatory year that coincides with the calendar year;
- 31 July for NSPs that have a regulatory year that is from April to March; and
- 31 October for NSPs with a regulatory year that coincides with the financial year.

Where the due date does not fall on a business day, the audited data will be due on the next business day.

1 Introduction

Economic benchmarking measures the efficiency of a firm in the use of its inputs to produce outputs. Accounting for the multiple inputs and outputs of network businesses distinguishes this technique from our other assessment techniques (which look at the partial productivity of undertaking specific activities or delivering certain outputs). It also accounts for the substitutability of different types of inputs and for the costs of providing different outputs.

We intend to apply economic benchmarking to measure the rate of change in, and overall efficiency of, NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts. We will also use economic benchmarking techniques to inform top down forecasts of opex (taking into account the efficiency of historical opex and expected rate of change) and total expenditure. That is, economic benchmarking will be used in conjunction with our existing assessment techniques to inform our assessment of NSPs' proposed expenditure.

We require a broad range of data so we can apply a range of economic benchmarking techniques and conduct sensitivity analysis on possible model specifications. This statement accompanies the final regulatory information notices (RINs) issued to network service providers (NSPs) to collect this information.

Need for the economic benchmarking RIN

The purpose of the new assessment techniques (such as economic benchmarking) is to assist the AER in determining a NSP's efficient level of expenditure. Throughout developing the Guidelines and selecting the assessment techniques, we have been mindful of the additional costs new techniques will impose on the NSPs and the AER. We consider the expected benefits of these techniques are significant enough to outweigh the additional costs they will impose.

We consider setting NSP expenditure allowances at efficient levels maximises social benefit. Given that energy is an essential input to the production of goods and services, the societal benefits from relatively small percentage efficiency gains could be highly material.

In developing the Guidelines and the economic benchmarking RIN, our ongoing consultation with NSPs has improved our understanding of the business and operational changes that will be required to comply with new data requirements. We acknowledge NSPs will face up-front expenses as a consequence of adjusting to new reporting standards. The AER may also incur additional costs associated with (among other things) collecting, validating and publishing data.

However, we base our selection of techniques on whether the benefits exceed the costs. Given the magnitude of NSPs' expenditure proposals, it would take relatively few inefficient projects to be identified and adjusted before the benefits would outweigh the additional costs imposed by our new assessment techniques and data requirements. Further, forecast capex and opex allowances for the transmission and distribution NSPs totals approximately \$61 billion over their current five year regulatory periods.² Balancing all these factors we consider the implementation of the new techniques and accompanying data requirements is net benefit positive.

² AER, *State of the energy market*, 2012, pp. 69-71.

Structure of this document

The statement explains the RIN requirements and how we came to a view on the final RINs, taking into account the submissions made on the draft RINs. In chapter 2 we consider qualitative matters raised on process, definitions, back cast data, auditing and statutory declaration. Chapters 3 to 9 explain, in light of submissions, the information requirements for each of the templates. These are:

- revenue
- opex
- regulatory asset base
- operational data
- physical assets
- quality of services
- operating environment.

2 Qualitative matters

The RIN requires independent assurance over the information the NSP provides and attestation by the NSP's chief executive officer (CEO) that the NSP has complied with the RIN. These requirements can impact the process, including the time, cost and effort to comply; particularly given we are seeking back cast data. However, assurance and attestation are necessary because they provide the AER with comfort that the NSP has responded to the RIN with appropriate rigour. Back cast data is essential because we need a time series to apply benchmarking going forward. In this chapter we discuss:

- issues of process
- general definitions
- back cast data requirements
- auditing and assurance requirements
- the statutory declaration.

2.1 Process issues

2.1.1 AER position

We have revised the timetable for the final RIN. NSPs have until 3 March 2014 to provide unaudited responses to the back cast data requirements and until 30 April 2014 to provide audited responses with a statutory declaration. This allows us to commence testing and validation of data early, ensuring time for a cross submissions process following publication of 30 April 2014 responses. It also provides a reasonable time period for independent assurance of the NSPs' RIN responses, which we require in order to ensure the robustness of the responses.

However, a RIN is an important legal instrument which requires full and complete compliance, regardless of NSPs' views about the quality of information they provide. We have, where possible, refined our information gathering approach to reduce compliance burden, but the quality and use of the information is for the AER to determine.

In response to submissions, we have clarified how we will deal with anomalies within RIN responses and made several changes to the RIN to make it clearer. This includes providing comprehensive instructions, clarification that the RIN is consistent with the Confidentiality Guideline and further explanation of how the RIN satisfies the requirements of the NEL.

2.1.2 Reasons for AER position

Submissions raised a number of matters of process, including:

- timing of the RIN response process
- concerns about the burden of providing back cast information and the quality of that information
- the basis on which the AER would amend audited information
- RIN compliance
- drafting of the written RIN

- confidentiality
- legal matters.

Timing of RIN response process and amendments

Some submissions considered the proposed timing of the RIN response process as required by the draft RIN could be improved. In essence, they considered we should:³

- remove the requirement for a statutory declaration on unaudited data
- not publish, or call for cross submissions on, unaudited data
- require the statutory declaration to be provided with audited data
- require audited data to be submitted in May 2014.

Some submissions also queried the basis upon which we would amend audited information.⁴

Timing

Based on these submissions and from feedback in bilateral meetings and workshops, we have modified the timing for the final RIN. The requirement for us to receive data early remains because we need to commence testing and validation on a large volume of data as soon as possible, notwithstanding that the data may change as a result of the auditing process.

However, we accept that publishing unaudited data and calling for cross submissions may have limited value if the data does indeed change. On the October 2013 workshop, some NSPs did not see value in a cross submissions process at all, or considered they would not have time to review the data of other NSPs. The cross submissions process is not compulsory, but it provides an opportunity for input into the testing and validation process, so we will still conduct it for stakeholders who are interested.

We also accept that officers of NSPs may be reluctant to sign off on unaudited data prior to audit. As a result—and due to delayed release of the final RIN—the timing for the final RIN responses and next steps are as set out in Table 2.1.

³ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 29-30, 34, Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 9; Aurora, *Draft economic benchmarking RIN submission*, 18 October 2013, pp. 1–2; CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 6; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, p. 5; Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 6; Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013, pp. 16–17.

⁴ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, p. 34; Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 9; Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013, p. 16.

Table 2.1 **Next steps**

Date	Milestone
3 March 2014	Unaudited RIN responses (for back cast data) set due
March 2014	Data checking/ validation process commences
30 April 2014	Audited and certified RIN responses (for back cast data set) due
May 2014	Publicly release data and seek cross submissions
July 2014	Economic benchmarking models finalised and results included in issues papers as part of revenue reset processes
September 2014	Results of economic benchmarking models included in annual benchmarking report

Amending audited information

While information we collect from this RIN process could potentially require later amendment or resubmission, this is a subsequent process to collecting the information, so it is outside the scope of the RIN. Our likely approach is below, but it is not cause for failure to provide or audit the information.

The purpose of commencing testing and validation on the unaudited data we receive on 3 March 2014 is to identify potential anomalies early in the process. We need to make sense of data from the entire National Electricity Market (NEM), so the earlier we commence this, the better. If we consider some information requires amendment by the NSP in the early stages of testing and validation, we may be able to bring this to the NSP's attention prior to it submitting the audited information.

If we identify anomalies after we receive audited information, we would prefer to resolve them with the relevant NSPs informally in the first instance. However, our expectation is that NSPs will comply with the RIN, so further interaction on data should be a matter of refinement rather than wholesale resubmission of templates. If we require any adjustments to information, we will publish the adjusted information.

Burden and information quality

We have refined our information gathering approach to make compliance with the RIN less costly and burdensome.

Some NSPs submitted that they had concerns about the burden imposed by the draft RIN, and the quality of the data for some variables, particularly where estimates will be required.⁵ Others consider that we should not issue the RIN at all because the data would not be accurate or meaningful.⁶

We have addressed these issues in the explanatory statement for the draft RIN and the explanatory statements for the draft and final Guidelines. Further, as discussed, we have refined our information gathering approach so as to make compliance with the RIN less costly and burdensome. We discuss

⁵ For example, ActewAGL, *Response to AER draft regulatory information notice for economic benchmarking*, 18 October 2013, p. 1; Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 1; CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, pp. 5-6; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, pp. 2-3; Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013, pp. 3-8.

⁶ Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, pp. 1-6.

these refinements later in this chapter. We have had regard to stakeholder submissions and other interactions in considering these refinements.

In terms of data quality, NSPs should concern themselves with RIN compliance. It is the AER's role to judge the quality and robustness of the data. We will consider data quality once we have received the information, during our testing and validation process.

RIN compliance

Some submissions raised issues with RIN compliance, including that we should:⁷

- not require NSPs to provide potentially misleading and unreliable information if a NSP may reasonably and legitimately not be able to provide data
- not require NSPs to provide data which they do not have
- maintain an open issues register during completion of the RINs to assist NSPs
- clarify the implications of an auditor not providing an opinion or providing an adverse opinion
- reconsider when we should require NSPs to stop estimating data for ongoing RIN compliance.

We provide our position in relation to these issues below.

Completing the templates

In order to comply with the RIN, a NSP must provide estimates for some variables, and depending on the variable this could be for particular years or for the whole back cast time series. The RIN requirements account for this because we understand that it is may not be possible to provide actual information for certain variables. This will vary between NSPs. In these circumstances, NSPs must provide their best estimates, and explain how they produced the estimate.

As foreshadowed in the draft RIN, the final RIN requires NSPs who cannot provide actual information for particular variables for the entire back cast data set, to provide their best estimates. A NSP may consider that its best estimate is not particularly robust. This does not matter. As long as the NSP genuinely considers that it is the best estimate that it can provide for the variable. Further, the NSP must provide an explanation in its basis of preparation: how it produced the estimate; why it is its best estimate; and concerns that it may have with the estimate. In this case, the NSP will have complied with the RIN.

Similarly, NSPs should not be concerned with the likelihood of estimates passing an audit. The RIN requires all NSPs to populate all input cells in the templates, irrespective of whether or not the NSP considers its data will pass an independent audit or review. That is for the auditor or assurance practitioner to decide, and is not an excuse for failing to complete the RIN.

No compliance issues arise when NSPs provide what they consider to be their best estimates and their explanations of how they have determined these, but they do arise where NSPs do not complete

⁷ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 18-19, 29; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013 p. 9; Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 1; ActewAGL, *Response to AER draft regulatory information notice for economic benchmarking*, 18 October 2013, p. 3; CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 5.

the RIN. We take non-compliance seriously and we can issue infringement notices and instigate civil proceedings against NSPs who fail to comply.

Compliance with all or part of a RIN is not optional. NSPs cannot choose which information to provide. Subject to a small number of exceptions (which are specifically noted) NSPs must complete all input cells in the consolidated version of the templates. By this, we mean that NSPs must enter a value into the cell that corresponds to the unit required. In most cases this is a number. For the avoidance of doubt, NSPs must not input 'N/A' or similar – this will amount to non-compliance.

However, we have amended the RIN to clarify that where:

- the templates (through orange or blue marking) and the instructions specifically state that a variable is potentially not applicable to the recipient NSP; and
- the NSP considers that that variable is also, in fact, actually not applicable to it,

then blacking out that variable will comply with the requirements of the RIN for the provision of back cast information. Such variables are limited to weather corrected maximum demand variables, certain operating environment variables, and certain opex variables.

This does not mean that we are allowing NSPs to not respond to part of the RIN. Rather, it means that, in the circumstances set out above, the correct response required by the RINs will be a blacked out cell. Any other use of blacked out cells, empty cells or entries such as "not applicable" will not comply with the terms of the RIN.

The reason the RIN allows a blacked out response in these limited circumstances is because we consider that it:

- would not be reasonable to require an estimate of these variables; and
- would be illogical for a NSP to enter '0' as an input.

There may be other input cells that a NSP considers do not apply to it. For these cells, the NSP must nevertheless provide an input, even if that input is '0'. There may be several variables that fall into this category. Some examples include the energy delivery variables, revenue variables or assets at voltages that the NSP does not operate.

For these variables, NSPs should consider the variable as a question and the input they are providing as a response to the question. For example, if a NSP uses peak or off-peak periods but does not use a shoulder period, the NSP can still provide a logical answer to the question 'what is the quantity of energy delivered at shoulder times?' by inputting '0'. Similarly, if a NSP does not receive any alternative control services revenue from fixed customer charges, the logical input is '0'.

It would not, however, be logical to answer the question 'what is the weather adjusted non-coincident maximum demand at the zone substation level?' with '0' because maximum demand (weather adjusted or not) cannot logically be '0'.

Further, this also means that NSPs must not enter '0' because they consider it would be difficult or burdensome to provide the information if a variable warrants a non-zero response.

Issues register

We are not opposed to the idea of a public issues register in principle. However, we are reluctant to include in the RIN itself the ability for NSPs to complete the templates 'subject to clarification from the AER'. This could potentially result in non-compliance. NSPs are of course welcome to contact us via [expenditure@aer.gov.au](mailto:expenditure@ aer.gov.au) while completing the RIN should they require any clarification.

Implications of no audit opinion or adverse audit opinion

The RIN requires independent audit and review of the templates and for NSPs to submit the audit and review reports with their completed templates on 30 April 2014 (and annually thereafter until 2024). If a NSP's auditor does not provide any opinion, the NSP will not comply with the RIN.

We expect adverse opinions would arise only in circumstances where a NSP does not complete the RIN templates or does not adequately explain how it has completed the templates (as the RIN requires this). We do not expect adverse opinions to arise simply because a NSP has provided an estimate because the RIN requires NSPs to provide estimates. If an auditor highlights deficiencies in the NSP's response because of, for example, insufficient audit evidence for a certain data point, this may result in a qualified opinion, but it would not necessarily amount to non-compliance. Compliance is necessarily a matter for us to determine upon receipt of the response and accompanying reports. However, in the interests of facilitating compliance, the RIN allows for the AER to discuss any deficiencies with the auditor and the NSP if necessary.

If NSPs are concerned about receiving an adverse opinion, they should consult with their auditors to ensure they are completing the templates and basis of preparation appropriately and in accordance with the RIN requirements.

Ongoing compliance

Some NSPs submitted that it may be necessary to provide some estimated values in relation to 2013 and 2014 regulatory years.⁸ We acknowledge that it may take some time to set up systems to commence reporting actual information for the majority of variables. While we expect NSPs to commence setting up reporting systems as soon as practicable, the RIN now provides that NSPs may provide some estimated values for the 2013 and 2014 regulatory years where necessary. For financial year NSPs, the 2015 regulatory year is the 2014/15 reporting year. Thereafter, we expect (excepting those variables that are inherently estimates) NSPs to collect and report using actual information.

Written RIN drafting

Some submissions considered we could improve the drafting of the written RIN by providing better instructions. Others provided drafting suggestions for the written RIN.⁹ We appreciate the feedback and suggestions. We have modified the written RIN and developed a standalone instructions and definitions document, which is attached to the final RIN as an appendix. Where we considered it appropriate, we have incorporated drafting suggestions.

⁸ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 5.

⁹ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, pp. 7, 10-12; CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 10 and attachment B; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013 pp. 7-13 and attachment 1.

Confidentiality

Some submissions considered the final RIN should clarify that the AER's Confidentiality Guideline will apply to the provision of information under the RIN.¹⁰ We confirm that the Confidentiality Guideline will apply and we have amended the written RIN accordingly.

Legal matters

Some submissions raised legal issues with the draft RIN. We respond to these submissions in this and the following sections.

Some NSPs submitted that in order to comply with the NER, we should:¹¹

- more fully explain reasons for requiring the information in each RIN template as required by s. 28K(1)(c)
- demonstrate the RIN is 'reasonably necessary' as required by s. 28F(1)
- consider the likely costs to NSPs as required by s. 28F(2)(b)
- demonstrate we have reason to believe NSPs are capable of providing the information (such as back cast data) as required by s. 28(1).

Further, the ENA submitted that the RINs cannot require NSPs to provide estimated data to the AER because it is information the NSP does not have.¹²

Compliance with NEL requirements

Section 28(1) of the NEL does not apply to RINs; it applies to the AER's general information gathering powers. However, we nonetheless consider NSPs are capable of providing the information required by the RIN. The RIN requires NSPs to provide their best estimates where it is not possible to provide actual information. It does not require actual information where NSPs cannot provide that information.

We also consider we have complied with the requirements of relevant provisions of the NEL. Appendix E of the final RIN contains a statement of reasons that references twelve months of consultation-focussed Better Regulation documentation that addresses:

- the need for the RIN;
- why we are collecting the information; and
- why the cost of compliance to NSPs and the AER is heavily outweighed by the benefits.

¹⁰ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 19-20; Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 10; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013 p. 7.

¹¹ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 7-9, 17-18; ActewAGL, *Response to AER draft regulatory information notice for economic benchmarking*, 18 October 2013, p. 2.

¹² Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 7-9.

RINs and estimates

We do not agree with the ENA's submission that RINs cannot require NSPs to provide information they do not have. The ENA's submission considered the authority for its proposition is *Dunlop Olympic Ltd v Trade Practices Commission (Dunlop)*.¹³ We are not convinced.

The AER may require NSPs to "prepare, maintain or keep" information in responding to a RIN.¹⁴ Such information may include:

- historic, current and forecast information (including financial information); or
- information that is or may be derived from other information in the possession or control of the service provider or the related provider to whom the instrument applies;

Forecast information is, by definition, an estimate. Information derived from other information is, by definition, information which is not immediately in the possession of the NSP. That is, the NSP is required to prepare that information such as forecast information, based on other information in their possession or control. Preparing back cast information should not be any different.

In any event, *Dunlop* concerned the operation of section 155 of the then *Trade Practices Act 1974* (as that legislation stood in 1982, many years before the drafting of the NEL and some decades before the introduction of RINs). Section 155 relates to the investigation of potential breaches of that legislation. In contrast, RINs can be used in any circumstance where the AER considers it reasonably necessary for the performance or exercise of its functions or powers under the NEL or the NER except enforcement, which is specifically excluded.¹⁵ The two provisions are quite different in purpose, drafting and effect.

Even if *Dunlop* were relevant to RINs, the excerpt relied on by the ENA omitted the preceding and following sentences. The full paragraph, with the ENA's selection italicised, stands for quite a different proposition than that submitted by the ENA:

We also find difficulty with the unqualified proposition that a s 155 notice cannot legitimately require the recipient to act as a "detective" It is true that *the recipient of a notice can only be required to furnish information which is in his knowledge or control and cannot be required to undertake a general investigation of matters beyond his control*. That is not, however, to say that compliance with the requirements of a s 155 notice may not well involve a degree of investigation to determine matters which are properly to be seen as being within the information or control of the recipient of a notice. This is particularly the case where the recipient is a company. Apart from documentary and computerized material which it owns, the knowledge and information of a company will ordinarily be the knowledge and information of its officers. The officer of a company responsible for formulating its response to a s 155 notice will commonly find it necessary to make inquiries of responsible officers, employees and agents as to relevant information in the same way as is necessary when a company is required to provide particulars, answer interrogatories or discover and produce documents in compliance with court orders in litigation or to provide information in compliance with the requirements of innumerable statutory provisions.

Dunlop broadened, rather than narrowed, the reach of s 155 (in the course of rejecting each of several challenges to the relevant s 155 Notice in dispute).

¹³ 40 ALR. 367

¹⁴ NEL, sections 28K-28M

¹⁵ NEL, section 28F(1), (3).

2.2 General definitions

2.2.1 AER position

In light of submissions, we have clarified several definitions in the final RIN, including the difference between actual and estimated information. We considered this necessary to facilitate compliance with the RIN. The distinction between actual and estimated information is particularly important because, in the case of financial information, the auditing and assurance requirements are different.

2.2.2 Reasons for AER position

Some submissions considered certain definitions required clarification and others provided some drafting suggestions. These include:¹⁶

- some of the general definitions
- regulatory year
- the distinction between actual information and estimated information.

General definitions

We have considered all comments and suggestions regarding general definitions and modified them for the final RIN where appropriate.

Regulatory Year

We have not modified the definition of regulatory year as it is consistent with the NER definition, albeit with additional text to confirm that the definition extends to pre-NER regulatory arrangements. We have, however, added an explanatory note to the definition to avoid confusion for NSPs whose regulatory reporting is on a financial year (July to June) basis. In essence, there is a six month lag for financial year NSPs. So, if the regulatory year as defined in the RIN is 2013, the equivalent financial year is 2012/13. 2012 equates to 2011/12, and so on. Table 2.2 in section 2.4.2 provides further explanation and summarises some of the information requirements for each NSP. For Aurora, the 2008 regulatory year will be a six month period because it changed from calendar year reporting to financial year reporting in 2008.

The distinction between actual and estimated information

In response to bilateral meetings, workshops and submissions on the draft RIN we have created specific definitions for 'actual' and 'estimated' information, given that financial information may include accounting estimates such as accruals and provisions. The distinction is important because the RIN requires a positive assurance audit of 'actual' financial information but a negative assurance review of 'estimated' financial information.

We circulated proposed definitions for further comment from NSPs and received several submissions. NSP views on our definitions varied. Some agreed with our definitions, others suggested modified or new definitions and others did not comment.¹⁷

¹⁶ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, pp. 17-18; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013 p. 7; Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 16-17; new submissions

For 'actual information', we have decided to adopt some of the ENA's definition and our definition as amended by Jemena. The ENA's definition extends to non-financial information as well as financial information but does not provide examples of accounting records. We consider, however, that the definition of 'estimated information' should be information that is not 'actual information'. Therefore, we do not agree with the ENA's suggested definition for estimated information because it is more complicated, which may result in a less clear demarcation between actual and estimated information. Ultimately this could lead to confusion for NSPs and their auditors. Accordingly, our definitions are:

Actual information: *information presented in response to the Notice whose presentation is materially dependent on information recorded in the NSP's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice.*

'Accounting records' include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate the NSP's regulatory accounts and responses to the Notice. 'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on.

Estimated information: *information presented in response to the Notice whose presentation is not materially dependent on information recorded in the NSP's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice.*

In its submission on the draft RIN, SA Power Networks considered we should clarify the threshold test of when it is not possible to provide actual information because most things are 'possible' given unlimited time and resources.¹⁸ We consider the definitions of actual and estimated information should now make this clearer. However, since NSPs do not have unlimited time to comply with the RIN, it would be best to interpret the definition of 'possible' in this context.

2.3 Back cast data

2.3.1 AER position

We have reduced the back cast data requirements for the final RIN. With the exception of Aurora, NSPs must provide eight years of back cast data (2006 to 2013 inclusive). Aurora will need to provide data from 2005 to account for the half year in 2008 referred to above. For NSPs who report on a financial year (April to March or July to June) basis, this equates to the 2005/06 to 2012/13 regulatory years. An eight year time series will provide a sufficient number of data points for implementing our economic benchmarking models. A ten year time series would be optimal, but NSPs suggested that the compliance and auditing burden associated with providing data for 2003 and 2004 would be significant.

¹⁷ Energy Networks Association, *AER 'Better Regulation' regulation information notices to collect information for economic benchmarking – further submission on draft RIN and explanatory statement*, 6 November 2013, pp. 6-9; Aurora, *Submission on draft economic benchmarking RIN*, 8 November 2013, p. 3; Jemena Electricity Networks, *Submission on vegetation management definitions and RAB allocation approach*, 8 November 2013, p. 1.; ElectraNet, *Submission on vegetation management definitions and RAB allocation approach*, 7 November 2013, p. 1; ActewAGL, *ActewAGL response to proposed definitions and approaches for the economic benchmarking RIN of 30 October 2013*, 7 November 2013, p. 2; Transend, *Vegetation management definitions and RAB allocation – Transend comments*, 7 November 2013; CitiPower and Powercor Australia, *Submission to AER on additional consultation on regulatory information notice for economic benchmarking*, 7 November 2013, p. 2; SA Power Networks, *Submission on vegetation management definitions and RAB allocation approach*, 6 November 2013; Energex, *Energex response to AER's email dated 30 October regarding the draft economic benchmarking RIN*, 6 November 2013, pp. 1-2.

¹⁸ SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013 p. 9.

To facilitate compliance, and given that we will continue to receive more information each year, in our view it is sensible to reduce the back cast data set. We consider it is reasonable to require eight years because this is equivalent to the number of years of historical data NSPs must provide when submitting expenditure forecasts with their regulatory proposals.¹⁹

2.3.2 Reasons for AER position

The majority of NSPs raised concerns about the requirement in the draft RIN for NSPs to provide ten years of back cast data. Concerns broadly related to:²⁰

- statutory obligations to retain records only extend to seven years, but there is no reason to assume the form and structure of the records will align with the RIN requirements
- the regulatory benefits to the AER would not justify the cost to the NSPs
- difficulty in determining the reasonableness and fairness of older information for NSPs and especially for auditors
- older information would, to be understood and comply with RIN requirements, require ancillary information that may have changed or may no longer exist
- accuracy and reliability of older information and increased need to estimate
- changes in NSP circumstances and reporting arrangements.

Some NSPs provided colour coded copies of the draft RIN templates to demonstrate their ability to comply with the back cast data set.²¹ These differed quite significantly depending on the variable and between NSPs. However, it is clear that for most NSPs, at least some of the RIN requirements would be quite difficult to comply with in the earlier years of the data set.

However, these templates also indicated that certain NSPs consider they have little or no data for some items that we consider would be fundamental to operating an electricity network. For example, according to the colour coded templates, it appears that:

- ElectraNet has little or no historical data on installed transformer capacity
- the NSW DNSPs have poor data on the circuit length and capacity of their conductors; specifically:

¹⁹ NER, clauses S6.1.1(6), S6.1.2(7), S6A.1.1(6) and S6A.1.2(7).

²⁰ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 11-13; Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 8; CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 2; ActewAGL, *Response to AER draft regulatory information notice for economic benchmarking*, 18 October 2013, p. 2; Aurora, *Draft economic benchmarking RIN submission*, 18 October 2013, p. 3; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, pp. 2-4; ElectraNet, *Response – draft economic benchmarking regulatory information notice*, 21 October 2013, p. 3; Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 6; Transgrid, *Draft economic benchmarking regulatory information notice*, 18 October 2013, p. 1; Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013, p. 2; Energy Networks Association, *AER 'Better Regulation' regulation information notices to collect information for economic benchmarking – further submission on draft RIN and explanatory statement*, 6 November 2013, p.10.

²¹ CitiPower, Powercor, ElectraNet, Jemena Electricity Networks, Ausgrid, Endeavour Energy, Essential Energy, SP AusNet.

- Essential Energy's templates suggest it has no data on any overhead or underground conductors (for either circuit length or capacity) prior to 2007 but excellent circuit length data from 2007
- Ausgrid's templates suggest it has excellent circuit length data from 2003 onwards for low voltage (LV) and 'other' overhead and underground conductors from 2003 until present, but poor quality data for all other conductors (for both circuit length and capacity)
- Endeavour Energy's templates suggest it has poor quality data for all LV conductors but reasonable quality data for all other voltages.

In response to these submissions, we found some publicly available information that provides some context.

In ElectraNet's 2008-2013 revenue proposal, for example, we found ElectraNet's installed transformer substation capacity as at 2007, by voltage.²² ElectraNet must also comply with the South Australian Electricity Transmission Code which has been in force in some form since 1999. Among other things, this Code includes transformer capacity reliability standards for exit points and a requirement to keep spare transformers.²³ We consider it would be difficult for ElectraNet to comply with its obligations under the Electricity Transmission Code or prepare regulatory proposals with little to no information about the transformer capacity for its network.

For the NSW DNSPs, we found an engineering report authored by Meritec. This report, which was prepared for the Independent Pricing and Regulatory Tribunal and used information submitted by the DNSPs, contains past data on (among other things) opex and asset information for all of the NSW DNSPs. It contains, for example, detailed line length and volume information for conductors, distribution transformers and circuit breakers split into voltage classifications and broken down by 5 year periods dating back to 1920.²⁴ It is surprising, therefore, that these DNSPs now consider their conductor data is so poor. While the newest information in this report is for 2002, we expect at the very least that the NSW DNSPs could interpolate between this older data and current data to generate estimates for the purposes of complying with the RIN.

Notwithstanding these issues, in the interests of reducing the cost and burden of complying with the RIN, we have reduced the back cast data set to eight years. Due to its half year in 2008, Aurora will need to provide the data from 1 July to 31 December of the 2005 regulatory year to make up the full 8 year back cast data set. Aurora may provide the full 2005 calendar year if it prefers, which would equate to a total of 8.5 years of back cast data.

We must collect back cast data for economic benchmarking. For the purposes of measuring change in productivity a long data set is preferable. An eight year data set should be sufficient to set up our economic benchmarking models. We do not consider there is merit in reducing the time series further because Economic Insights requires at least eight years of data for index-based economic benchmarking such as multilateral total factor productivity.²⁵ In addition, eight years is appropriate because NSPs must provide historical data for eight years when submitting expenditure forecasts with

²² See, for example, ElectraNet, *ElectraNet Transmission Network Revenue Proposal – Volume 1: 1 July 2008 to 30 June 2013*, 31 May 2007, p. 19.

²³ For example, Essential Services Commission of South Australia, *Electricity Transmission Code TC/07 (Version 2)*, 1 July 2013, section 2.

²⁴ See, for example, Meritec, *Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers – Final Report*, September 2003, pp. 55, 72, 89, 103.

²⁵ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. viii.

their regulatory proposals (at a much more disaggregated level than the economic benchmarking data requirements).²⁶

2.4 Auditing requirements

2.4.1 AER position

We have reduced the auditing timeframe for back cast data to five years (from ten years). We will still have confidence in the data because the majority of the back cast time series will be subject to independent review and the three unaudited years will be subject to statutory declaration. However, it will significantly reduce the compliance burden for NSPs. We also removed the requirement for a systems audit. We recognise NSPs have not had systems in place to split the high level data required for economic benchmarking in the manner the RIN requires. Given this, a systems audit would be an additional burden for NSPs but may not provide additional comfort for the AER.

The final RIN requires NSPs to prepare a basis of preparation that supports their responses to the information requirements. This will assist the auditors, and will be important from our perspective for assessing compliance. We will further assist auditors by requiring NSPs to complete separate templates for actual information and estimated information. This will clearly separate the information for the purposes of auditing in accordance with the different standards required under the RIN.

We have not adopted the ENA's suggestion of a risk based auditing framework because it would provide us with little comfort that the data will be audited to a particular level of assurance.

RIN responses must be independently audited and reviewed and NSPs must provide the audit and review reports to us. We will apply our Confidentiality Guideline when considering confidentiality claims in relation to the audit and review reports.

NSPs can use suitably qualified non-financial assurance practitioners to audit non-financial information if the AER currently allows this for the NSP's annual reporting, provided the assurance practitioner meets the requirements of ASAE 3000.

2.4.2 Reasons for AER position

We received some helpful submissions from NSPs (particularly the ENA) on the draft RIN auditing requirements. Submissions suggested we could make the following improvements:²⁷

- prepare Regulatory Accounting and Assurance Guidelines that set out a framework for providing information to the AER, providing guidance for NSPs and auditors
- provide more information and guidance on audit requirements

²⁶ The NER require NSPs to provide, with their regulatory proposals, information relating to their capex and opex for the current regulatory period and the preceding regulatory period. Two years of the current period is based on estimates or forecasts and the remainder is past actual data. NER, clauses S6.1.1(6), S6.1.2(7), S6A.1.1(6) and S6A.1.2(7).

²⁷ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 6, 10-11, 21-29, Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, pp. 14-15, CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, pp. 2; Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013, pp. 14–15; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, p. 12; Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 6; ENA, 6 Nov Submission, pp. 2-12; Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p.2.

- require NSPs to provide information with the RIN responses that explains the basis upon which the responses were prepared, including accounting policies and assumptions
- reduce the timeframe and scope of the audit would significantly reduce the costs to NSPs
- remove the requirement for a systems and controls audit because it would be unnecessary, difficult, and the auditor would not be able to conclude on the matters required by the AER
- consider using ASRE 2405 as the auditing standard for estimated financial information rather than ASAE 3000
- use a risk based framework that is attuned to the materiality of the risk being addressed by the audit or assurance report
- amend Appendix C of the RIN to be more consistent with the scope of an auditor's or assurance practitioner's reports permitted by the Auditing Standards
- remove the requirement for the auditors' reports to be in a form publishable by the AER.

We have adopted most of the suggestions submitted by NSPs. Some key changes are discussed below.

Audit timeframe

The most significant is our decision to reduce the auditing timeframe from ten years to five years. NSPs have requested that, to ease compliance burden, the AER reduce the back cast period to five years and request negative assurance over that period.²⁸ Feedback we received in submissions and bilateral meetings suggested that there would probably be diminishing returns from auditing data in the earlier years, for some of the information we are seeking. In essence, the further back in time, the more difficult it is for NSPs to prepare the information and the more work for the auditor. In turn, this results in greater costs for NSPs and difficulty in complying with the RIN in the time we require. In particular, SA Power Networks advised that the costs of its audit would be halved if we reduced the audit timeframe to five years.²⁹

Therefore, we have chosen to be more flexible to facilitate NSP compliance with the RIN. As we explain in section 2.5, however, the CEO of the NSP must attest that the NSP has complied with the RIN for the entire back cast data set in a statutory declaration.

Due date for audited data

We have changed the due date for audited information. As we raised in meetings and workshops following the draft RIN, we would postpone the cross submissions process until after we received audited data, because there would be limited value in seeking submissions on data that could potentially change. However, to accommodate this, the draft RIN audit due date of May 2014 would be too late to commence cross submissions and provide sufficient time for us to develop the economic benchmarking models.

Therefore, and given the delayed release of the final RIN, audited back cast information for all NSPs is due on 30 April 2014.

²⁸ For example, Energy Networks Association, *AER 'Better Regulation' regulation information notices to collect information for economic benchmarking – further submission on draft RIN and explanatory statement*, 6 November 2013, pp. 9–10.

²⁹ SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, p. 4.

Going forward, the most recent regulatory year's audited data is due on:

- 30 April for NSPs with a regulatory year that coincides with the calendar year;
- 31 July for NSPs with a regulatory year that coincides with the an April to March financial year; and
- 31 October for NSPs with a regulatory year that coincides with a July to June financial year.

Where the due date does not fall on a business day, the audited data is due on the next business day. Table 2.2 provides further details for each NSP.

Table 2.2 Information requirements by NSP

NSP	Example RIN year	Regulatory year equivalent	Unaudited back cast data due	Audited back cast data due	Audited 2014 Year due	Audited 2015 Year due ^a
CitiPower, Powercor, JEN, SP AusNet (distribution), UED	2013	2013	3 March 2014	30 April 2014	30 April 2015	30 April 2016
SP AusNet (transmission)	2013	2012/13	3 March 2014	30 April 2014	31 July 2014	31 July 2015
ActewAGL, AusGrid, Aurora, ElectraNet, Endeavour, Energex, Ergon Energy, Essential, Powerlink, SA Power Networks, Transend, Transgrid	2013	2012/13	3 March 2014	30 April 2014	31 October 2014	31 October 2015

Note: (a) The audited 2015 year is the last year where estimates may be used. Thereafter, NSPs must provide actual information except for those variables that are inherently estimates (per the instructions and definitions appendix to the RIN).

Basis of preparation

The final RIN requires NSPs to prepare bases of preparation for their RIN responses. While, due to time constraints, we have not adopted the ENA's suggestion of developing Regulatory Accounting and Assurance Guidelines, we have provided significantly more guidance to NSPs on how to complete (and comply with) the RIN templates and the requisite bases of preparation. This guidance is contained in the Instructions and Definitions document, which is an appendix to the RIN.

Separate versions of the RIN templates

Following discussions with the ENA, the final RIN requires NSPs to complete three separate versions of the templates. This will allow the auditors and assurance practitioners to understand exactly which information is estimated and which is actual. This is important because, particularly for financial information, the auditing standard is positive for actual information but negative for estimated information. Separate templates will also enable the auditor or assurance practitioner to clearly identify what they have audited.

NSPs must complete the consolidated version in accordance with the RIN and the instructions and definitions. NSPs must then copy all actual information into the version of the templates for actual information and copy all estimated information into the version of the templates for estimated information. NSPs are required to provide all three versions of the templates to us.

Risk based framework

We have chosen not to adopt a risk based auditing framework. Our preference is to require:

- positive assurance in relation to actual financial information; and
- negative assurance in relation to all remaining information for all audited years and for all variables.

We consider that a risk based framework would provide us with little comfort that information would be audited to a particular level of assurance because it would leave that decision to NSPs' auditors. Our approach is also consistent with the approach we take for annual RINs.

Publishable audit reports

RIN responses must be independently audited and reviewed and NSPs must provide the audit and review reports to us. In a bilateral meeting, the ENA submitted that we should not publish audit or review reports due to the risk that a member of the public could potentially use the audit or review report for an unintended purpose, suffer loss, and take legal action against the audit firm.

If a NSP considers audit or review reports should be confidential, they must comply with our Confidentiality Guideline. Rather than create a specific exception for audit and review reports, we will apply the Confidentiality Guideline when considering confidentiality claims. As provided by the Confidentiality Guideline, we will assess each confidentiality claim on its merits.

Review of non-financial information

For annual reporting RINs for some NSPs, we currently allow qualified non-financial assurance practitioners (such as engineering firms) to review non-financial information. In the interests of RIN compliance and cost minimisation for NSPs, we are prepared to allow this for the economic benchmarking RIN if this is current practice for annual RINs. Non-financial assurance practitioners must meet the requirements of ASAE 3000.

2.5 Statutory declaration

2.5.1 AER position

The final RIN contains a modified statutory declaration. NSPs are no longer required to certify that the RIN responses can be relied upon by the AER to conduct economic benchmarking. It is for the AER to determine the usefulness of the information once we have received it, rather than the NSP. NSPs are also no longer required to complete the declaration prior to independent audit of their data.

NSPs will, however, need to certify that the earlier years of the back cast data set are true and accurate (for actual information), or the NSP has used its best estimates (for estimated information). The NSP's CEO must make the statutory declaration. This should be administratively less burdensome for the NSP than the draft RIN, which required a Director to make the statutory declaration.

2.5.2 Reasons for AER position

We have amended the statutory declaration for the final RIN in a number of respects. The changes are identified below.

Most NSPs made submissions on the statutory declaration in the draft RIN. Some submissions also helpfully provided suggested drafting for the statutory declaration.³⁰ Broadly, submissions raised issues regarding:³¹

- the form of the statutory declaration, particularly the requirement that NSPs certify that the information is fit for the AER's requirements
- signing a declaration on unaudited data
- ambiguity regarding who should sign the declaration.

First, we agree with submissions that it may be unreasonable for an officer of a NSP to certify that the information provided in response to the RIN is fit for the AER's requirements. We will be satisfied if NSPs provide the information in accordance with the RIN. This includes NSPs providing actual information unless it is not possible to do so and best estimates in all other instances. We consider it is necessary to retain this requirement to ensure the robustness of responses. However, it is for the AER to determine the usefulness of the information once we have received it.

Second, we have removed the requirement for NSPs to provide a statutory declaration on the unaudited back cast data, which is due on 3 March 2014. Most NSPs were uncomfortable certifying unaudited information, albeit some of the uncomfortableness may have related to the strict nature of the draft statutory declaration. Regardless, NSPs are now required to provide the statutory declaration with the audited data on 30 April 2014.

NSPs should note, however, that due to relaxed auditing requirements, there will be three years of unaudited data (2005 to 2007 inclusive) that they must certify using the statutory declaration. That is, the statutory declaration for the final RIN applies to the full eight years of back cast data, but the audit requirements apply only to the most recent five years. This is to ensure that the information received in response to the RIN is robust. Given that the final RIN statutory declaration is more akin to a certification of reasonableness of key assumptions (that a NSP must submit with forecast capex and opex proposals), we consider this is reasonable.³² We will publish all eight years of back cast data that has been provided in response to the RIN.

We also confirm that the CEO is the officer responsible for making the statutory declaration. Administratively, this should place less of a burden on NSPs given that a CEO should be able to make the declaration without needing to hold a meeting with the NSP's Board of Directors.

³⁰ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013; Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013.

³¹ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 31-33; CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 4; Aurora, *Draft economic benchmarking RIN submission*, 18 October 2013, p. 2; SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, pp. 5, 11; Transgrid, *Draft economic benchmarking regulatory information notice*, 18 October 2013, p. 1; Transend, *Submission on draft economic benchmarking regulatory information notice (RIN)*, 18 October 2013, p. 2; Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, pp. 10–13; Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, pp. 7-8, 12-14.

³² See, for example, NER, S6.1.1(5), S6.1.2(6), S6A.1.1(5) and s6A.1.2(6), which require the directors of a NSP to attest to the reasonableness of the assumptions on which the NSP's capex and opex forecasts are based.

3 Revenue

Economic benchmarking outputs can be measured on an 'as billed' basis or on a broader 'functional' basis. We are collecting revenue data to allow for the application of 'as billed' or billed outputs specification in addition to a functional outputs specification. The 'as billed' basis measures outputs in terms of the services for which businesses charge customers. In order to weight the outputs under a billed output specification it is necessary to collect data on revenues. The objective of the revenue worksheet is to collect revenues in accordance with the main outputs for which the NSP's bills its customers to weight outputs under the billed output specification.

3.1 AER position

In the final RIN we have clarified the revenue reporting requirements and removed the obligation for DNSPs to report revenues for network services.

To clarify the reporting framework and how the worksheet is to be populated, we are requiring NSPs to report their revenues in accordance with the requirements of their annual financial statements.

Further, to address NSP submissions we have amended the definitions for revenue by chargeable quantity variables.

3.2 Reasons for position

Clarifying the revenue reporting requirements will make it easier for NSPs to complete the templates. We have removed the requirement to report revenues for network services because it would be burdensome for NSPs to report and is at a level of detail that, on reflection, would not be necessary.

In response to submissions we have considered the appropriate reporting framework for revenues. Amongst other matters these submissions requested whether revenues are to be reported:

- in an accrual basis
- inclusive of taxes
- inclusive of the effects of incentive schemes
- inclusive of any over or under recoveries against forecast revenues.³³

Submissions also requested clarity regarding the reporting framework (which includes the cost allocation approach and accounting principles and policies) to be applied when reporting revenues.³⁴ We consider that it is appropriate that the reporting framework applied in NSP's historical financial statements be applied for the requested revenues for economic benchmarking. Hence we are requiring NSPs to report their revenues in accordance with the manner that they reported them within their annual financial statements. However, these are to be disaggregated in accordance with the data requirements for economic benchmarking.

Requiring revenues be reported in a manner consistent with the regulatory accounts will mean that at the total level the reported information should reconcile to the regulatory accounts. As these accounts

³³ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 5, bilateral meetings with Jemena and Networks NSW.

³⁴ Energy Networks Association, *AER 'Better regulation' regulation information notices to collect information for economic benchmarking – submission on draft RIN and explanatory statement*, 18 October 2013, pp. 21–30.

have been audited in the past, we anticipate that this will reduce the costs of auditing the RIN response. Further, this will reduce the reporting burden on NSPs as they will not apply different accounting principles and policies to those that they applied in the past (unless this is required for the disaggregation of revenues to our requested categories).

Under a billed outputs specification the outputs are weighted in accordance with the prices that NSPs charge for their services. As a result, differences in the way in which NSPs report their revenues are not a concern so long as they reflect the manner upon which they charge their customers.

Further, we consider the reported revenues should be comparable across NSPs. This is because the regulatory financial statements are derived by disaggregating statutory financial statements. These statements are completed in accordance with the consistent requirements of the Australian accounting standards.

Some DNSPs noted the difficulty in providing estimates for network services, particularly in separating network services from standard control services.³⁵ The purpose of requesting revenue split out in accordance with network services is to determine output weights as a part of a billed outputs specification. On further consideration, we do not consider the difference between the revenue for network services and standard control services to be material for the purpose of obtaining weights in a billed outputs specification. Hence we have removed the requirement to separately report revenues for network services from the RIN.

The NSW DNSPs submitted that controlled load energy revenues and deliveries should be captured as standalone variables. This was because it would be misleading to report controlled energy deliveries under the off-peak category as controlled loads may be delivered at any time, not just during off-peak periods.³⁶ We are not convinced that controlled load energy deliveries will be material in the context of economic benchmarking. However, we have amended the templates to require separate reporting of controlled load revenues and energy deliveries so the significance of these variables can be tested.

³⁵ This issue was raised in a number of bilateral meetings. It was also raised in: Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 5. Essential Energy, *Microsoft Excel workbook, Essential colour coding of draft RIN*, 18 October 2013.

³⁶ NSW Networks, p.8.

4 Opex

We are requesting opex information as opex is one of two broad input categories along with capital that is typically used in economic benchmarking. Most Australian network economic benchmarking studies have included just one aggregate opex input component.³⁷ For opex we require a consistent basis of comparison across time and across NSPs. The basis of comparison for DNSPs is network services and the basis of comparison for TNSPs is prescribed transmission services.

4.1 AER position

We have clarified the reporting framework for opex in the instructions and definitions document. The instructions provide for both a consistent time series of opex, and a time series that should directly reconcile to NSP's previously submitted financial statements.

In particular we have amended the instructions to only require opex for backcasting of current CAMs if the difference between current and historical CAMs is material. As suggested by the ENA, we have based our definition of materiality on that of the Australian Accounting Standards Board (AASB). For clarity, we have also specified that a material change in opex is half a percent of total opex in the year that the change occurred.

We have added a table to collect information on provisions such that the effect of the movement in provisions on productivity and change in productivity can be taken into account.

To provide clarity, the opex instructions now provide that any margins and opex associated with dual function assets is to be included in the opex worksheet.

In response to submissions, we have amended the instructions for the high voltage opex estimate to provide additional guidance. In particular, where actual data is unavailable the opex can be estimated based on the opex incurred by the DNSP for a transformer of the same MVA capacity. Where this is not known, it can be approximated by the observed maximum demand for that customer.

4.2 Reasons for position

Cost allocation approach

We received several submissions requesting more clarification of our opex instructions. Energex submitted that it has amended its CAM multiple times and it is unclear which CAM should apply in the historical opex categories tables.³⁸

Ergon Energy submitted that it was unclear if the AER was expecting the template to be resubmitted every time a new CAM is implemented.³⁹ SA Power Networks noted recasting its CAMs will give rise to an excessive amount of work for little benefit and there would be no material difference between historic regulatory values for opex and data recast using the current CAM. Networks NSW also submitted that only material differences in CAMs should be accounted for.⁴⁰

³⁷ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 54

³⁸ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 7.

³⁹ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 19.

⁴⁰ Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 9.

SA Power Networks also note that the AER does not require the CAM to be recast for the historical RAB.⁴¹

We have clarified the reporting framework for opex in the instructions and definitions. We are requesting that opex be reported in accordance with both:

1. The requirements of the NSP's annual financial statements and cost allocation approach in place for each regulatory year, and
2. The requirements of the annual financial reporting statements and cost allocation approach in the most recent completed regulatory year for all regulatory years

At the total level, the information we are seeking is to be reported in accordance with the annual financial statements and cost allocation approach. This should reconcile to audited amounts reported in financial statements. This will reduce the auditing burden on NSPs.

Where there has been a material change in cost allocation approach or annual reporting requirements it may be necessary to account for this in productivity analysis. Hence, where there has been a material change in the cost allocation approach or annual reporting requirements, we are also requiring NSPs report their historical opex in accordance with their current cost allocation approach and regulatory reporting requirements.

The process for this is set out in our instructions and definitions.

We note the concerns of NSPs regarding the requirement to back cast opex in accordance with their current cost allocation approach. However our position is consistent with the NER requirement for NSPs to categorise their historical opex in accordance with that of their forecasts in their regulatory proposals.⁴² These NER requirements provide that NSPs must quantify the effect on historical opex of any change in their capitalisation policies. Further our cost allocation guidelines provide that we may make amendments to cost allocation methods (CAMs) conditional on NSPs restating their historic or forecast financial information on a basis that is consistent with the amended CAM.⁴³

Whether or not NSPs must restate their historical opex depends upon whether there has been a material change in the cost allocation approach. On the ENA's recommendation we have based our definition of materiality on the definition of materiality developed by the AASB. However, we note that the ENA's proposed definition of materiality is not consistent with the AASB's most recent definition of materiality. We have used the AASB's most recent definition as the basis for our definition of materiality.

The accounting standard AASB 1031 defines materiality and provides guidance on how the definition of materiality is to be interpreted. This standard suggests thresholds for what constitutes a material change in the context of annual financial statements. For the avoidance of doubt, we have also specified a threshold as to what constitutes a material change in opex in the instructions and definitions.

In response to SA Power Network's submission, we are not requiring the historical RAB be restated in accordance with the current cost allocation approach. This is because we consider that a change in

⁴¹ SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, pp. 4–5.

⁴² NER, clauses S6.1.1(6), S6.1.2(7), S6A.1.1(6) and S6A.1.2(7).

⁴³ AER, *Electricity distribution network service providers Cost allocation guidelines*, June 2008 p. 15.

AER, *Final, Electricity transmission network service providers Cost allocation guidelines*, September 2007 p. 11.

the cost allocation approach will have less of an impact on RAB values. CAM changes will be less material given that significant investment in the RAB occurred before the advent of incentive regulation. Further requesting NSP to recast the historical RAB in accordance with a current CAM would be overly burdensome.

Clarification of particular opex variables

We received several submissions requesting clarification on what is to be included in some of the opex variables.

CitiPower and Powercor submitted that it was not clear if opex is to be adjusted for provisions inclusive of margins.⁴⁴ As previously stated, we are requiring NSPs report their opex in accordance with their annual reporting statements so opex will not be provision adjusted.

However, we note that the movement in provisions can have an effect on the productivity of NSPs. To account for this we have added a table requesting detail on the movement in provisions. We will then use this data to make an assessment on whether an adjustment for provisions is required.

In regards to margins we now explicitly note that margins are to be included in opex. This is consistent with the regulatory financial statements where we request that opex be reported inclusive of margins. Where regulatory financial statements request opex both inclusive and exclusive of margins we have clarified that opex is to be reported inclusive of margins.

We received submissions that noted that data on opex for high voltage customers was not available.

CitiPower and Powercor submitted that it was not provided with the information on the type of assets that are owned, operated and maintained by directly connect end-users and there is no basis on which it can estimate another parties' opex.⁴⁵ This issue of not having the data to estimate the high voltage customers variable as also raised in our bilateral discussions with the DNSPs.

We have included extra instructions in the RIN that provides guidance on how a DNSP can estimate the opex for high voltage customers. This includes clarifying that the estimate only applies to the operations and maintenance costs associated with the transformer owned by the high voltage customer. We acknowledge DNSPs are unlikely to have data on this variable and the data will have to be estimated based on other sources of information such as comparable opex for similar assets or observed maximum demand.

We note the issue of dual function assets included in ActewAGL's RAB is discussed in the Assets (RAB) section below. To be consistent with the inclusion of dual function assets in the RAB, it is also appropriate to include any opex associated with dual function assets.

Ergon Energy noted that the definition of connection services may differ across jurisdictions.⁴⁶ To ensure that the definition of connection services is consistent, we have adopted the definition of connection services in our connection guideline.⁴⁷

⁴⁴ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 2.

⁴⁵ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 11.

⁴⁶ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p.17

⁴⁷ AER, *Connection charge guidelines for electricity retail customers Under chapter 5A of the National Electricity Rules*, Version 1.0, June 2012

Ergon Energy also noted that operating and maintaining connection assets would not be classified as a connection service under the RIN's definition.⁴⁸ It is not our intention that the operation and maintenance of connection assets be classified as a connection service for the purposes of economic benchmarking. Instead we consider that this should form part of the network services. We have amended the definition of network services to clarify this.

⁴⁸ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p.17

5 Assets (RAB) Worksheet

Economic benchmarking of NSPs requires data on the price, quantity and value for each output and input, together with data in relation to key operating environmental conditions. The model specification recommended by Economic Insights provides for three aggregated categories of capital inputs, which are overhead lines, underground cables, and transformers and other capital.

The relative weighting of each category of capital and the 'value' of capital rely on measures of financial capital in each NSP's RAB. The value of each capital input is the 'Annual User Cost of Capital' (AUCC). Calculating the AUCC requires data in relation to:

- the opening value of the asset
- depreciation
- the opportunity cost of funds used to purchase the asset
- capital gains.

In the context of the 'building blocks' framework, the AUCC proposed is consistent with measures of the 'return-on' and the 'return-of' capital.

The relative weight of each category of capital is derived using the value of capital input (again the AUCC), and the quantity of capital measured by a physical proxy of capital (for example, lines capital input quantity measured in Megavolt ampere (MVA)-kilometres derived using the sum of kilometres of line by voltage class, multiplied by the weighted average MVA rating for each class). Therefore, the data to calculate the AUCC is required for each capital input category employed in the economic benchmarking model. This requires allocation of the RAB into the specified capital input categories.

5.1 AER position

We have provided NSPs with additional instructions in relation to completing the Assets (RAB) worksheet. They include a common or standard method for NSPs to complete the Assets (RAB) worksheet (the Standard Approach). The Standard Approach is to be followed by all NSPs.

Where NSPs believe they have sufficient information to provide a consistent RAB disaggregation into the categories in the Assets (RAB) worksheet that better reflects the values of those assets than the specified Standard Approach. NSPs that do this will still need to complete the Assets (RAB) worksheet using the Standard Approach.

We have also provided further clarification of the instructions and definitions in relation to the Assets (RAB) worksheet. Where AER-approved RAB values use estimated data (for example, for the last year of the previous regulatory period), where possible those forecast values should be replaced with actual values. Further, substation land should be included in the substation asset variable. Separate values for substation land may be provided in accompanying documentation to the RIN response. In relation to treatment of capital contributions by DNSPs, where previous values of the RAB have included capital contributions, capital contributions should be reported in the Assets (RAB) worksheet. This data should be provided as a separate entry in the category provided in the spread sheet and should include cash and physical asset contributions. We have also renamed categories in the DNSP RIN that were previously labelled 'Distribution Assets 66kV and above', to 'Distribution Assets 33kV and above'.

We have amended the instructions to reflect that TNSP RAB (Asset) values should be provided on an 'as commissioned' basis. DNSP RAB (Asset) values are to be provided on an 'as incurred' basis.

5.2 Reasons for position

Asset (RAB) Instructions

The Assets (RAB) Instructions provide:

- a Standard Approach to provide Assets (RAB) values that is to be followed by all NSPs
- that those NSPs that have sufficient information, may also provide a consistent RAB disaggregation in addition to the Standard Approach.

NSPs' submissions included a range of views to the AER in relation to their ability to:

- disaggregate their RAB into the categories requested in the draft Economic Benchmarking RIN
- roll forward each category over the time period requested
- achieve consistency between the sum of the disaggregated rolled forward amounts and their total RAB for each of the years requested.⁴⁹

Some NSPs indicated that they view this as a relatively straight-forward task. However, most NSPs submitted they either have insufficient information to do this or view this as a difficult task. Some NSPs submitted that they have concerns that NSPs will adopt different approaches and have requested the AER to provide guidance on how this should be done. A few NSPs submitted that they have apprehensions in relation to the AER specifying a common approach given that NSPs vary widely in terms of the amount of RAB information held at a disaggregated level and how readily it can be allocated to the ten categories requested. A number of NSPs submitted that an approach they preferred involved dividing the RAB value by calculated depreciation to calculate residual asset lives.⁵⁰

We have considered submissions made in relation to this issue. As discussed previously, given that even those NSPs with more finely disaggregated RAB data will still have to disaggregate some key categories to match the requested categories, we have:

- specified a Standard Approach that is to be followed by all NSPs
- also allowed for those NSPs that have sufficient information, to provide a consistent RAB disaggregation in addition to the Standard Approach.

We have specified a Standard Approach to provide guidance to those NSPs who submitted that they were otherwise not able to complete the Assets (RAB) worksheet because they either had insufficient information to do this or viewed this as a difficult task. The Standard Approach may better ensure that the information is consistent between NSPs. We have also allowed for those NSPs that believe they have sufficient information that better reflects the values of the assets, to provide a consistent RAB disaggregation in addition to the Standard Approach. In both cases we require the provision of a supporting worksheet detailing the calculations undertaken.

⁴⁹ AER Workshop with stakeholders in relation to auditing requirements and how RAB data should be estimated, 2 October 2013.

⁵⁰ AER Workshop with stakeholders in relation to auditing requirements and how RAB data should be estimated, 2 October 2013.

United Energy requested additional explanation and clarification in relation to the 'optional additional approach'.⁵¹ The optional additional approach applies only where a NSP believes that it has sufficient information to provide a consistent RAB disaggregation into the RAB Assets worksheet that better reflect the values of the assets, compared with the Standard Approach. In this case, the NSP must also report RAB values in accordance with the Standard Approach. In both cases, worksheets detailing the calculations must be provided.

Some NSPs submitted that the Standard Approach may result in inaccuracies because it relies on the depreciated replacement cost of assets made for the most recent year for which the RAB financial data cannot be directly allocated.⁵² In cases where disaggregation is required for the whole time period then this will be the 2013 regulatory year. The Standard Approach has been developed in response to NSP's requests for us to provide an approach that will be adopted consistently between NSPs. Where NSPs believe they have sufficient information to provide a consistent RAB disaggregation into the RAB Assets worksheet that better reflect the values of the assets, they may also provide this using the Optional Additional Approach.

Some NSPs, submitted that information such as unit rate replacement costs for each asset class may not be available.⁵³ Where unit rate replacement cost information is not available, NSPs are required to provide their best estimate of the depreciated replacement cost for aggregate asset categories. This is not intended to be a very detailed exercise.

Capital contributions, substation land and forecast capex

Energex⁵⁴ and Ergon Energy⁵⁵ submitted that measures of the RAB should include capital contributions. Energex submitted the inclusion of substation land in the substation asset variable would result in inaccuracies because land is not depreciated.⁵⁶ Energex submitted that clarification should be provided in relation to whether the use of forecast capex in the roll forward is appropriate.⁵⁷

We have further clarified the instructions in relation to the Assets (RAB) worksheet in response to these submissions. For example, these include that when using AER-approved RAB values that use estimate/forecast data (for example, for the last year of the previous regulatory period), those forecast values should be replaced with actual values where possible. Further, substation land should be included in the 'substation asset' variable. Separate values for substation land may be provided in documentation accompanying the RIN response. Finally, in relation to DNSPs' treatment of capital contributions, where previous values of the RAB have included capital contributions, capital contributions should be reported in the Assets (RAB) worksheet. Contributions should also be provided as a separate entry in the variable provided in the spread sheet.

⁵¹ United Energy, *Re: Economic Benchmarking Regulatory Information Notice (RIN)* 13 November 2013, p. 2.

⁵² ActewAGL, *ActewAGL Response to Proposed Definitions and Approaches for the Economic Benchmarking RIN of 30 October 2013*, 7 November 2013, p. 1. CitiPower and Powercor Australia *Submission to AER on Additional Consultation on Regulatory Information Notice for Economic Benchmarking*, 7 November 2013, p. 1.

⁵³ Jemena, *Comments on Approach to Disaggregating the RAB*, 8 November 2013, p. 1.

⁵⁴ Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 8.

⁵⁵ Ergon Energy, *Draft Regulatory Information Notice and Explanatory Statement - Collection of Information for Economic Benchmarking*, 18 October 2013, p. 20.

⁵⁶ Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 8.

⁵⁷ Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 8.

Roll forward capex, asset lives and easements

Energex sought clarification on the appropriate CAM to use to derive the capex roll forward.⁵⁸ CitiPower and Powercor also noted they did not record easements.⁵⁹ Powerlink also sought clarification in relation to whether accounting lives or regulatory values should be used in relation to estimating asset lives.⁶⁰ CitiPower and Powercor proposed the use of RAB value divided by depreciation as a simple method of calculating residual asset lives.⁶¹

Where relevant, NSPs should 'roll forward' capex that is based on that year's CAM. Where necessary, data in relation to asset lives should be a high-level estimate based on engineering knowledge within each business. Where DNSPs have previously reported and/or recorded values for easements, these values should be provided in the Assets (RAB) worksheet. Otherwise, this should be included in the remaining categories. These cells in the Assets (RAB) worksheet have been shaded orange to reflect this requirement. Where relevant, aggregated data that includes easements, should be identified.

Some TNSP's submitted that the RAB (Asset) values should be provided on an 'as commissioned' basis.⁶² We have amended the instructions to reflect this. DNSP RAB (Asset) values are to be provided on an 'as incurred' basis.

⁵⁸ Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 9.

⁵⁹ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 20.

⁶⁰ Powerlink, *Powerlink Response - AER Draft Benchmarking RIN*, 18 October 2013, p. 2.

⁶¹ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 12.

⁶² Powerlink, *Economic Benchmarking – Vegetation Management and RAB Allocation*, 8 November, p. 2.

6 Operational data

The operational data worksheet includes output variables used in our primary and alternative model specifications. Our primary model specification includes measures of customers, interruptions and capacity. Alternative model specifications also include energy delivered and disaggregated customer types. Our operational data worksheet collects different measures of energy delivered, customers and maximum demand. We consider energy delivery, customers/connection points and maximum demand separately below.

6.1 Energy delivery

6.1.1 AER position

We have created an additional variable "Energy received from TNSP and other DNSPs not included in the above categories" in response to submissions noting that some DNSPs do not record on-peak, shoulder and off peak energy received from TNSPs and other DNSPs. Collecting this information will account for DNSPs that do not record on-peak, shoulder and off-peak energy received from TNSPs.

We are collecting information on embedded generation because we may have to take into account the differences that these sources of generation may have on DNSPs' cost structure.

We have now clearly defined embedded generation, and DNSPs will be now required to report non-residential embedded generation and roof top solar separately. We have disaggregated embedded generation into non-residential embedded generation and rooftop solar because we expect DNSPs to have more accurate data for the larger non-residential embedded generation relative to rooftop solar data. For this reason back cast data on the rooftop solar variable is only required if the DNSP collects data however this variable will be required for future economic benchmarking RIN responses.

Non-residential embedded generation includes only specific generation plant, where energy into the DNSP would be metered and charged under a contract arrangement. This does not include domestic roof-top solar, but would include solar farms and wind farms if connected to the DNSP system.

6.1.2 Reasons for position

Several DNSPs submitted that they were unable to separate energy received from TNSPs and other DNSPs by time of receipt. Jemena noted it did not charge on this basis.⁶³ Ergon Energy submitted that another variable would be required to capture energy received from TNSP and other DNSPs by time of receipt similar to the 'other' variables used in our other energy delivery categories.⁶⁴

We have created a new variable that captures energy received where it is not charged on a peak, off-peak or shoulder period. This ensures that all energy received from TNSP and other DNSPs will be recorded.

This variable is not intended to capture energy received where a DNSP charges based on time of use and did not record this data. If a DNSP does receive energy based on time of use and does not record this data, it is required to estimate the proportion of energy received during peak, off-peak and

⁶³ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 22, CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 12, Jemena, Excel.

⁶⁴ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 22

shoulder periods. This is to ensure that this output can be linked to revenues under a billed outputs specification.

However, if a DNSP does receive energy from TNSP and other DNSPs and it is not on a time of use basis, it may record the energy received in this new variable. This change ensures that all energy regardless of the charging basis will be captured.

Networks NSW raised concerns about the clarity of the RIN in relation to energy delivered. Networks NSW noted that it will assume energy deliveries will need to reconcile to the weighted average price cap (WAPC) figures.⁶⁵

We consider the energy delivered variable should reflect the actual historical energy delivered if this data is available. If data used for the WAPC is a best estimate at the time data must be provided to the AER, then this can be provided. For the purposes of economic benchmarking we consider the energy delivery variables should reconcile with the NSPs primary source delivery data rather than other models that use the same data.

We agree our definition for the embedded generation variable in the draft RIN did not provide sufficient guidance on what is to be included in embedded generation.

Ergon Energy asked if the embedded generation variables included household photovoltaic installations.⁶⁶ As discussed above we have split the embedded generation variables between rooftop solar and non-household embedded generation. We expect DNSPs to have more reliable data on non-household embedded generation as this source of embedded generation is likely to be under a contract arrangement.

Rooftop solar will become increasingly important as domestic rooftop solar installations increase. We require back cast data for rooftop solar only if it is currently being collected by the DNSP.

CitiPower and Powercor submitted that they are only able to provide net energy flow from embedded generation rather than total.⁶⁷ We have decided to continue to require non-household embedded generation, professional or contracted sources of embedded generation because it may have an impact on the planning of a DNSP's system.

6.2 Customer numbers

6.2.1 AER position

We have clarified the definition of a customer to include both active and de-energised customers in response to Energex's submission. This is because DNSPs are still required to provide and maintain network services to de-energised customers. For further clarity we have also specified that deactivated NMI's are not to be counted as customers.

⁶⁵ Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 10.

⁶⁶ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 21

⁶⁷ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 13.

6.2.2 Reasons for position

Energex sought clarification on whether residential customers comprise active and de-energised customers or active customers only.⁶⁸ In response to this submission we have amended the definition to clarify that customers include both active and de-energised NMIs. DNSPs are required to build and maintain the infrastructure to service de-energised customers and therefore these customers should be included in the outputs measure. Additionally, NMIs will often be de-energised and re-energised as a result of customers changing premises. In these circumstances the premises is still active and hence the de-energised NMI should be reflected in the output measure.

6.3 Connection point numbers

6.3.1 AER position

We have amended the worksheet to require the number of entry and exit points by voltage levels rather than by main grid voltage and other grid voltages. Specifying the entry and exit points by voltage level will provide a clearer picture of the total number of entry and exit points and the TNSP's distribution of entry and exit points. We are requesting the number of entry and exit points as at system normal conditions.⁶⁹

6.3.2 Reasons for position

The amendments we have made to the worksheet are in response to submissions requesting clarification on our definition for connection point numbers. Electranet requested more clarification on the connection variables.⁷⁰ Powerlink questioned what "main grid voltage" is and noted it would be either 275kV or 330kV.⁷¹

The requirement to specify the number of entry and exit points at each voltage level is a clearer requirement than providing the number of entry and exit points at 'main' and 'other' transmission voltages especially where a TNSP may have a similar number of connection points at different voltages.

Powerlink also submitted that under outage conditions and/or abnormally high power transfers, energy may exit and re-enter Powerlink's network. Powerlink asked if a connection point can change over time.⁷²

The purpose of our connection point variables is to provide an indicator of the requirement for transmission services a TNSP has to provide at connection points. These services are a necessary part of maintaining the quality, reliability and security of supply.⁷³ Since the connection point variables are a broad measure that acts as an indicator of the requirement for transmission services, we consider the number of entry and exit points under system normal conditions is sufficient to provide this information.

⁶⁸ Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 10.

⁶⁹ Electranet, *Microsoft Excel workbook, Electranet benchmarking data source*, 18 October 2013.

⁷⁰ Electranet, *Microsoft Excel workbook, Electranet benchmarking data source*, 18 October 2013.

⁷¹ Powerlink, *Powerlink Response - AER Draft Benchmarking RIN*, 18 October 2013, p. 3.

⁷² Powerlink, *Powerlink Response - AER Draft Benchmarking RIN*, 18 October 2013, p. 3.

⁷³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 36.

6.4 Maximum demand

6.4.1 AER position

We have amended the instructions for weather adjusted maximum demand variables to only be required where the NSP have calculated weather adjusted maximum demand for historical data. All NSPs will be required to provide his data for future economic benchmarking RIN responses.

We have amended the definition of coincident maximum demand to refer to the demand at the zone substation or terminal station at the time of when the summation is greatest, which is then weather normalised in response to submissions requesting clarity on which point in time maximum demand calculations should be done.

We have amended the terminal station variables to refer to transmission connection point in response to submissions requesting clarification on the meaning of terminal station. The term transmission connection point is an established point for a DNSP where the transmission network meets the distribution network.

We have amended the DNSPs worksheets to require an annual power factor conversion for all years. This variable was already included in the TNSP's draft economic benchmarking RIN template. For the DNSP template this variable was defined in the definitions worksheet but was left out of the operational data worksheet in error.

6.4.2 Reasons for position

We received submissions requesting clarification on the basis in which maximum demand should be calculated. In particular, CitiPower and Powercor noted the coincident weather adjusted maximum demand is inconsistent with the definition previously applied by the AER in the 2010–15 electricity distribution price review (EDPR) RIN. Further CitiPower and Powercor maintained that it was impossible to estimate coincident weather adjusted maximum demand as fiend in the draft economic benchmarking RIN. CitiPower and Powercor recommended the definition to mean the demand at the zone substation or terminal station coincident with the system peak, which is then weather normalised.⁷⁴ Ergon Energy also requested clarification on the point of coincidence for coincident peak demand and the point at which weather correction is performed.⁷⁵

We have amended the definition of non-coincident maximum demand to be the summation of raw annual maximum demands for the requested asset level irrespective of when they occur. For co-incident maximum demand this will be summation at the point at the time when this summation is greatest. After raw maximum demands have been calculated it can be normalised for weather.

SA Power Networks noted it only measured coincident maximum demand at a system-wide terminal station level and only in MW (and not MVA).⁷⁶ We require SA Power Networks to provide an estimate coincident maximum demand at the zone substation level. We require power factor conversions to convert MW and MVA measures, SA Power Network will have to use a power factor conversion to estimate the coincident maximum demand in MVA.

⁷⁴ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 12.

⁷⁵ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 21

⁷⁶ SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, Attachment 2 p. 2.

Transgrid submitted that requesting maximum demand in MVA is non-sensible for a transmission network, as it takes into account reactive power. Reactive power is generated and absorbed throughout the network while controlling power flows.⁷⁷

We acknowledge the shortcomings of using maximum demand in MVA terms raised by Transgrid and will consider this when analysing the maximum demand data we receive in response to the RIN.

For our weather adjusted maximum demand variables, we note not all NSPs currently calculate weather adjusted maximum demand and it was not clear in the draft explanatory statement if the NSPs were required to provide this data.

ActewAGL noted in the explanatory statement to the draft RIN, weather adjusted maximum demand was not required; however subsequently in the same document the AER also provided a methodology to calculate weather adjustments.⁷⁸

SA Power Networks noted it would only be able to provide weather adjusted maximum demand from 2012/13 onwards.⁷⁹ Energex's submitted that calculating weather adjusted maximum demand values prior to 2007 would be resource intensive.⁸⁰ We have now made it clear in our RIN that weather adjusted maximum demand data is only required if the NSP already collects this data. This addresses SA Power Networks and Energex's concerns about data availability.

In response to our variables that require data at the terminal station level, DNSPs requested clarification on what the term terminal station meant. Ergon Energy asked if the transmission connection point is the terminal station.⁸¹ Energex also asked if the terminal station related to the connection point.⁸² Clarification on what is meant by terminal station was also raised in bilateral discussions.

To provide clarification on what is meant by terminal station we have amended the name of the relevant variables from at the terminal station to at the transmission connection point. The data collected for these variables have not changed and the new variable name better reflects the DNSP's understanding of the variable.

We received a submission requesting clarification on power factor conversions. Ergon Energy asked what should be assumed for the weather adjusted power factor.⁸³ Our worksheet does not include any weather adjusted power factor conversion variables. We are only requesting power factor conversions at each voltage level for unadjusted data.

While we included power factor conversion variables in the TNSP operational data worksheet, we did not include it in the DNSP operational data worksheet although these variables were in the instructions and definitions worksheet. This was an oversight, and we have now also added the power factor conversion variables to the operational data worksheet in the final RIN for DNSPs. The power

⁷⁷ Transgrid, *Draft economic benchmarking regulatory information notice*, 18 October 2013, p. 2.

⁷⁸ ActewAGL, *Response to AER draft regulatory information notice for economic benchmarking*, 18 October 2013, p. 3.

⁷⁹ SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, Attachment 2 p. 1.

⁸⁰ Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 11.

⁸¹ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 21

⁸² Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 21, Energex, *Energex Response to AER's Draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 11.

⁸³ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 21.

factor conversion is supporting data that better helps us understand how the MVA and MW measures of maximum demand were estimated if a NSP can provide maximum demand in only MVA or MW terms but not both.

7 Physical Assets

Economic benchmarking requires a quantity measure of the capital service flow used by the NSP into the production process. However, this cannot be directly observed. Only the quantity of the stock of capital can be observed at any point in time. Therefore, it is necessary to use proxy measures of capital service flow.

The recommended specification provided by Economic Insights provides physical measures of capital to be used as a proxy for capital service flow from assets. The capital service flow is assumed to be proportional to the capital stock and assumes a one-hoss shay physical depreciation profile.

We are requiring data on the quantities and capacities of physical assets. Capacities are measured in MVA-kms for lines and cables and in MVA for transformers. As a measure of the capital service flow we are requiring data on the capacities of physical assets.

7.1 AER position

We have clarified a number of definitions in relation to categories in the Physical Assets worksheets for both the DNSP RIN and the TNSP RIN. For example, in relation to DNSP assets that apply to 'Other overhead/underground voltages', and for TNSP assets that apply to the "other transmission voltages" categories, additional rows should be added to the worksheet where the NSP has assets with voltages other than those already specified in the tables. An additional row is to be added for each other voltage level. The voltage level and the length of the asset, must be provided.

We have provided additional clarification in relation to the definition of network weighted average MVA capacity by voltage class. NSPs are required to provide estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances, taking account of limits imposed by thermal or by voltage drop considerations as relevant. This information will be used to calculate an overall MVA x km 'carrying capacity' for each voltage class under normal circumstances. NSPs with summer peaks are to provide summer ratings while NSPs with winter peaks are to provide winter ratings. If a NSP's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak .

Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, the NSP may split the circuit capacity by the ratio of overhead and underground lengths to form estimates of the overhead capacity and underground capacity components.

We have further clarified the definition of the variable 'Zone substation transformer capacity' in the DNSP Physical Assets sheet to include cold spare capacity. The instructions now provide that the DNSP is to report transformer capacity involved in intermediate level transformation capacity (for example high voltages such as 66 kV at the zone substation level to the distribution level of 11 kV) in either one or two steps. The DNSP is to report the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included if relevant) and include both energised transformers and cold spare capacity. Assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing. This rating is to be the lower of the thermal capacity of transformers or the zone substation exit feeder capacity.

We have also provided additional clarification for the DNSP variables: 'Total zone substation transformer capacity where there is a single transformation'; 'Total zone substation transformer

capacity'; 'Cold spare capacity of zone substation transformers included in total zone substation transformer capacity' and in relation to the categories associated with public lighting.

In relation to the Physical Assets TNSP worksheet, we have also further clarified a number of additional instructions and definitions. This includes in relation to 'Installed transmission system transformer capacity' that provides that the NSP is to report transformer capacity involved in transformation levels indicated within the table. For the purposes of these measures the transmission system includes transformers, overhead and underground lines and cables in service that serve a transmission function. The transformer capacities variables are to be reported inclusive of cold spare capacity. For each level, the TNSP is to report the summation of normal assigned continuous capacity or rating (with forced cooling or other capacity improving factors included if relevant). It is to also include capacity of tertiary windings as relevant and assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing. The TNSP is not to include step-up transformers at generation connection location.

Further, in relation to the variable 'Transformer capacity for directly connected end-users owned by the end-user', the instructions now provide that the TNSP is to report transformer capacity at connection point to directly connected end user where the capacity is owned by the directly connected end user. Where the NSP knows what the directly-connected customer's transformer capacity is, it should include that information. Where this information is not available to the NSP, it is to report a summation of non-coincident individual maximum demands of each such directly connected customer whenever they occur (ie the summation of a single annual MD for each customer) as a proxy for capacity within the customer's installation. The variable should be the sum of the direct information where this is available and of the proxy MVA measure where the direct measure is not available.

7.2 Reasons for position

Some NSPs have indicated that some data in relation to the physical assets sheet is not available.

CitiPower, Powercor and ElectraNet requested further clarification in relation to the variable 'cold spare capacity'. Cold spare capacity does include transformers that are located in stock for allocation to projects. Energex⁸⁴, CitiPower and Powercor⁸⁵ requested clarification on the meaning of 'first level' and 'second level' transformation. We have amended the definitions to provide further clarification.

Jemena noted the distribution feeders within its network are partially undergrounded along their routes but there are no fully underground circuits from zone substations to the end of the feeder. Energex submitted that many feeders on its network include a combination of both overhead and underground components.⁸⁶

Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, the NSP may split the circuit capacity by the ratio of overhead and underground lengths to form estimates of the overhead capacity and underground capacity components.

⁸⁴ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 12.

⁸⁵ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 12.

⁸⁶ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 12.

Some DNSPs submitted that they are not able to provide information in relation to the 'Distribution transformer capacity owned by High Voltages Customers'.⁸⁷ If the transformer capacity owned by customers connected at high voltage is not available, the summation of individual maximum demands of high voltage customers should be reported whenever they occur (ie the summation of single annual MD for each customer) as a proxy for delivery capacity within the high voltage customers.

⁸⁷ Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 11. Ergon Energy, *Response to Draft Regulatory Information Notice and Explanatory Statement - Collection of Information for Economic Benchmarking*, 18 October 2013, p. 22.

8 Quality of service issues

Quality of service is an important dimension of a NSP's outputs. Quality of service measures include the frequency and length of network outages and the loss of energy through transmission and distribution.

8.1 AER position

We have changed the estimation methodology for calculating the major event day (MED) threshold for the distribution reliability parameters. Under our previous approach to exclude the effects of major event days, NSPs would have needed detailed outage data going back to 1998. We have amended the instructions to specify that the MED threshold is to be calculated for the 2012 regulatory year in accordance with the STPIS. This is then to be applied as the MED threshold for all regulatory years prior to 2012. This will significantly reduce the information burden of reporting against the reliability parameters.

Further a number of NSPs identified some errors in the Quality of services worksheet, and requested clarification regarding some of the reliability information that we requested in the draft RIN. We have amended the instructions to address these errors and clarified the RIN, where appropriate.

8.2 Reasons for position

CitiPower and Powercor noted the calculation of a MED for any given year requires a further five years of historical data. CitiPower and Powercor recommended the definition be amended to apply the 2009 MED to prior years as an approximation.⁸⁸ Further, Networks NSW noted that changes in the definition of MEDs may result in estimation and reduced accuracy of the data.⁸⁹

We have amended the MED threshold instructions to specify that the MED threshold should be calculated for the 2012 year and then applied to previous years. This will reduce the number of years of historical reliability data required to complete the worksheet by five. Further, as the calculations will be based upon the most recent available reliability data this approach should be the least burdensome. Under this approach a consistent MED threshold will be applied to all years of historical data. The application of a consistent MED threshold will make reliability data more comparable over time.

We note the Networks NSW's concern that changes in the definitions of MEDs may result in estimation and reduced accuracy of reported information. As our STPIS MED definition is consistent across networks this should not be an issue.

A number of businesses sought clarification regarding the definitions of reliability parameters. NSPs also identified some errors in the worksheet.⁹⁰ To clarify the requirements of the worksheet we have changed the names of some of the reliability variables. We have amended the worksheet to remove the errors identified in submissions. This involved correctly stating the units of measurement for the reliability parameters.

⁸⁸ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 13.

⁸⁹ Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, p. 11.

⁹⁰ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, pp. 3–4, CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 13, Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p.23

Ergon Energy noted that the definitions of service performance parameters proposed by the AER include outages beyond the service fuse. Ergon Energy noted that it only started collecting information on these outages for the 2010-11 regulatory year.

Ergon Energy also noted that prior to the 2010-11 regulatory year, it calculated its reliability performance using average monthly customer numbers whereas the service target performance incentive scheme (STPIS) requires that these calculations be based on an average of customers at the beginning and end of the year.

We are not convinced that these differences in the manner in which Ergon Energy calculated reliability data previously will make a material difference to its reported reliability performance as required by the worksheet.

Additionally, Ergon Energy collects and reports detailed reliability data to comply with the STPIS. We consider that this detailed data could be used to calculate the effect of these differences to determine if they are material. If the differences are material, then Ergon Energy can use the measure of the difference to calculate an estimate of reliability performance as required in the worksheet.

ElectraNet noted for service parameter 2 'number of events greater than x and y system minutes'⁹¹, that the x and y thresholds were different for the 2003-08 to 2008-13 periods.⁹² We have clarified that where multiple x and y thresholds apply all thresholds should be stated together with the years for which they applied.

Energex sought clarification regarding the type of thermal capacity to calculate capacity utilisation. Energex noted that it could be interpreted as nameplate capacity, emergency capacity or another type of capacity.⁹³ We have clarified the meaning of thermal capacity in the instructions and definitions. We have specified that for the purpose of this measure, thermal capacity is the rated continuous load capacity of zone substation transformers (with forced cooling or other capacity improving factors included if relevant). For those zone substations where the thermal capacity of exit feeders is a constraint, we have specified that the thermal capacity of exit feeders should be used instead of transformer capacity.

⁹¹ Where x and y related to the NSP's thresholds.

⁹² Energex, worksheet 7 – quality of service.

⁹³ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p.12

9 Operating environment factors

Operating environment factors can have a significant impact on network costs and measured productivity. We are collecting information on operating environment factors to account for differences in productivity across network that may be caused by factors that are exogenous to a NSP's control.

In, practice the number and type of operating environment factors that can be included in economic benchmarking studies is limited by data availability, correlation with other included variables and degrees of freedom considerations.

9.1 Vegetation management

Vegetation management is an obligation for NSPs which will differ across networks depending on the operating environment of that network.

9.1.1 AER position

To capture the extent of vegetation management works required we have amended the vegetation management variables to be:

- the number of vegetation maintenance spans and the total number of spans,
- average vegetation maintenance span cycle
- average number of trees per vegetation management span
- average number of defects per vegetation management span
- tropical proportion
- bushfire risk.

We previously collected the number of spans on a one, two or three year cycle. The new vegetation maintenance span related variables directly capture the extent of vegetation management works required to be undertaken by a NSP by measuring the number of trees and defects per span. The average vegetation maintenance span cycle accounts for cycles beyond three years.

We have also reduced the period over which we are requiring back cast data to be provided for vegetation management operating environment factors. NSPs are only required to provide one year of data, but have the option of providing five years back cast data if it is available. We aren't convinced that a long time series is required in order to construct an operating environment factor for vegetation management. That said, the provision of a time series from some NSPs will allow us to test whether these variables materially change year to year.

For DNSPs, we have decided to require the vegetation management span variables to be disaggregated by rural and CBD/urban vegetation maintenance spans. Vegetation management practices can differ for urban and rural areas, which in our view may necessitate different vegetation management plans which may not be captured if we use an average figure.

9.1.2 Reasons for position

We consider the new vegetation management variables more adequately capture the following three major aspects that may impact on the costs associated with vegetation management.

1. Topography – the type of environment the NSP's lines pass through. For example lines that run through trees will require more vegetation management than grasslands.
2. Regrowth – the rate at which vegetation regrows. For example a NSP in a tropical region or coastal region may have to undertake the same vegetation clearance tasks more frequently than a NSP in a dry inland region.
3. Legislative requirements – these are requirements beyond a NSP's control and provides an additional cost.

Vegetation maintenance span variables

The draft economic benchmarking RIN requested the number of spans on a one, two or three vegetation management cycle. In response to these variables Energex, Ergon Energy, CitiPower and Powercor noted the vegetation management cycle varied within a span and did not necessarily follow a one, two or three year cycle.⁹⁴ Essential Energy noted its cycles ranged from one to five years and that it would need to average its data to fit into the defined cycles.⁹⁵ CitiPower and Powercor submitted that the previous span cycle variables were unworkable because different parts of a single span may be inspected on different cycles.⁹⁶

We consider an average measure of the vegetation management cycle will capture the different cycles across and within spans for NSPs. It also is more flexible and reflective of the NSP's vegetation management cycles than requesting the data on a defined cycle basis (e.g. on a one, two or three year cycle). Although the average measure of the vegetation management cycle does not measure the variation of a NSP's cycles it does provide a broad measure of the relative frequency of vegetation management activities undertaken by NSPs.

Vegetation maintenance cycles

Vegetation maintenance cycle rates do not provide a full picture of the extent of vegetation management activities required to maintain a vegetation maintenance span. A NSP with a shorter average cycle does not necessarily require more vegetation management activities than a NSP with a longer cycle. The choice of vegetation management cycles includes a trade-off between mobilisation, inspecting/scoping costs and cutting costs. For example, a two year cycle will require more frequent mobilisation and cutting activities than a five year cycle for a given maintenance span. However the extent of the cutting activities for a two year cycle will be less than that of a five year cycle.

Average number of trees per span

To provide more information on the extent of vegetation in a NSPs network, we have requested the average number of trees per maintenance span. The number of trees in a vegetation maintenance span is an overall measure of the amount of vegetation management activities a NSP is required to undertake. This variable does not include trees that do not require any vegetation management to comply with the NSPs vegetation management obligations.

⁹⁴ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 12, Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, pp. 23–24, CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 13.

⁹⁵ Essential Energy, *Microsoft Excel workbook, Essential colour coding of draft RIN*, 18 October 2013.

⁹⁶ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 14.

We note some NSPs do not record the number of trees requiring vegetation management in their network and this will need to be estimates. We have provided several methodologies that can be used to estimate this variable in our instructions and definitions. The methodologies including the use sampling techniques and records of vegetation scoping works, field survey or data from the Bureau of Meteorology (BOM). The extent to which an estimation methodology is applicable will be dependent on the vegetation management data recorded by the NSP and its contractors.

Average number of defects

We have also introduced a variable to capture the average number of defects per vegetation maintenance span. This variable identifies the extent to which a NSP is complying with its vegetation management obligations. All else equal a NSP with more defects per span may not have an appropriate cycle for the vegetation maintenance span. The number of defects is also an input in one of the methodologies for estimating the number of trees.

We consider the maintenance cycle, number of trees and number of defects variables, overall, better reflect the topography and regrowth of a NSP's network than the previous maintenance cycle measure. The new variables take into account the overall amount of work as well as the average frequency of work undertaken by the NSP.

CitiPower and Powercor submitted that the AER should collect data on the number of spans cut per year where the DNSP has responsibility to cut the spans and the number of spans inspected per year. They estimate cutting contributes to approximately 85 per cent of the total costs of vegetation management.⁹⁷

The variables proposed by CitiPower and Powercor measure the extent of works undertaken by the NSP. To some extent the number of spans cut and the number of spans inspected per year is dependent on the NSPs own vegetation management plan. Some NSPs may choose to cut more frequently but cut less of a tree.

Our average number of trees variable measures the extent of the vegetation a NSP must maintain to be compliant with their vegetation management obligations. Further, this variable is independent of the NSPs vegetation management plan. Our average vegetation maintenance cycle variable will capture the frequency a NSP undertakes its vegetation management works and the number of defects measures the compliance. As a result, we consider that these variables will better capture vegetation related operating environment factors that are beyond a NSP's control.

Tropical proportion and urban/rural split

The tropical proportion variable has been amended to provide greater clarification on what constitutes a tropical area. A tropical area is a 'hot humid summer' or 'warm humid summer' region as defined by the BOM.

Ergon Energy noted it has diverse vegetation zones which impact vegetation management cycles, in particular tropical areas which experience high rainfall, high temperatures and high vegetation growth rates.⁹⁸ Aurora submitted major factors in plant growth are water availability, nutrient availability and nutrient balance, although at a given level of these factors a warmer temperature gives greater

⁹⁷ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 14.

⁹⁸ Ergon Energy, *Response to draft regulatory information notice and explanatory statement – collection of information for economic benchmarking*, 18 October 2013, p. 23.

growth.⁹⁹ CitiPower and Powercor also noted the tropical area measure should be the number of spans located in tropical areas.

It is important to account for diversity of weather conditions. We note there is a variety of environmental conditions that may affect vegetation growth rates. We have obtained rainfall data from the BOM and we would expect that overall a tropical area is likely to experience greater vegetation growth rates than a non-tropical area. It would not be possible to determine the nutrient balance and nutrient availability for the vegetation in each NSP. The tropical area measure is a broad measure that we expect may impact growth rates and can be objectively measured.

The BOM maps provide clarity on the areas we consider experience tropical weather conditions. We have amended the variable to require the number of spans in these areas.

For DNSPs we have also required the data to be disaggregated into urban/CBD and rural vegetation maintenance spans. We consider there may be differences between vegetation management programs between these two broad geographic regions due to differences in tree density and the type of vegetation management activities required.

We are proposing to capture vegetation management zones as a part of our category analysis. This information could be incorporated into our economic benchmarking analysis, once this data is provided later in 2014.

United Energy submitted that Energy Safe Victoria (ESV) defines rural as high bushfire risk area and urban as low bushfire risk area. For consistency and cost reasons United Energy submitted that the rural and urban split for vegetation maintenance spans should be reported based on the high and low bushfire risk area split.¹⁰⁰

We request urban and rural areas to be consistent with our customer definitions for urban and rural. It is not appropriate for the urban and rural definitions to be based on the level of bushfire risk where the definition of bushfire risk is subject to change. For example, in its white paper the ESV has proposed a change to the definition of an urban area with the intention that land defined as being urban should not be able to carry fire.¹⁰¹

An urban or rural maintenance span is to be consistent with our definition of customer types rather than based on the bushfire risk. We acknowledge there may not be a material difference between the ESV's definition of urban and rural compared to our definition. Where there is no material difference a NSP may use other sources of data with similar classifications for urban and rural maintenance spans.

Bushfire risk

We have removed the 'bushfire legislative requirements' variable in response to submissions. It has become apparent that this variable did not capture the extent or difficulty of addressing bushfire risk. We are still obtaining the extent of bushfire risk through the 'bushfire risk' variable.

⁹⁹ Aurora, *Submission on draft economic benchmarking RIN*, 8 November 2013, p. 2

¹⁰⁰ United Energy, *Re: Economic Benchmarking Regulatory Information Notice (RIN)* 13 November 2013, pp. 1–2.

¹⁰¹ Energy Safe Victoria, *Review of statutory provisions relating to the mitigation of bushfire risks arising from electricity assets*, 2 November 2013, p. 13

Essential Energy noted that it was required under legislation to look at its whole network and assess what sections need to be done at what times to mitigate risk.¹⁰²

The original purpose of the 'bushfire legislative requirements' variable was to capture the differences in legislative requirements across NSPs. However, this variable does not adequately capture the qualitative differences between NSPs. The qualitative differences to relate to the difficulty in complying with bushfire related legislation. A variable that captures the existence but not the requirements of bushfire legislative risk would not be able to capture this.

We consider information relating to the qualitative differences between NSPs can be obtained separately to the economic benchmarking RIN. Any research conducted by NSPs on the quantitative and qualitative impacts of different legislative requirements such as bushfire risk can be submitted to us as a part of our model testing and validation process.

Energex noted bushfire risk data is only available from 2007 onwards because the Queensland Fire and Rescue Service did not define high risk bush fire areas for use by Energex.¹⁰³ Networks NSW submitted that bushfire areas are not legislated and are defined by local councils and change on a year by year basis.¹⁰⁴

The 'bushfire risk' variable measures the number of vegetation maintenance spans in 'high' bushfire risk as classified by a person or organisation with the appropriate expertise on fire risk such as:

- the NSP's jurisdictional fire authority
- local councils
- insurance companies
- the NSP's consultants
- local fire experts

While there may be inconsistency in what is classified as a high bushfire risk assessment between states, a 'high' bushfire risk assessment determined by an appropriate expert will still provide us with information on the extent of the exposure of a NSP's network to bushfire risk. The NSPs will only be required to report yearly changes on the extent of bushfire risk where there are material changes between periods.

Backcast data

We received several submissions that noted back cast data was not available for vegetation management related variables.¹⁰⁵

¹⁰² Essential Energy, *Microsoft Excel workbook, Essential colour coding of draft RIN*, 18 October 2013.

¹⁰³ Energex, *Energex response to AER's draft Economic Benchmarking Regulatory Information Notice and Better Regulation Explanatory Statement*, 18 October 2013, p. 13.

¹⁰⁴ Networks NSW, *Response to the draft economic benchmarking regulatory information notice*, 18 October 2013, pp. 11–12.

¹⁰⁵ Ausgrid, *Submission on vegetation management definitions and RAB allocation approach*, 8 November 2013, p. 1. Ergon Energy, *Submission on vegetation management definitions and RAB allocation approach*, 13 November 2013, p. 1. Aurora, *Draft economic benchmarking RIN submission*, 18 October 2013, p. 2. Electranet, *Submission on vegetation management definitions and RAB allocation approach*, 7 November 2013, p. 1. Energex, *Energex response to the AER's email dated 30 October 2013 regarding the draft economic benchmarking RIN*, 6 November 2013, p. 3. CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 4.

We have amended the worksheet in response to these submissions so NSPs may provide five years of back cast data if they currently record information on these variables and one year of estimated data if they do not.

One year of data will allow us to compare the extent of vegetation management requirements across NSPs. One year of data will not allow us to compare vegetation changes over time. However it will give us an indication of the extent of vegetation that is inherent to the location of the NSP's network. Although variations in weather over time may affect the density of vegetation one year of data will be sufficient to determine broadly if vegetation is a key factor in a NSP's service area.

9.2 Weather stations

9.2.1 AER position

We are collecting weather station information to gauge extreme weather conditions such as high wind gusts and heat waves in a NSP's service area. This information will assist us in developing an operating environment variable that accounts for differences in weather across NSPs.

In the draft RIN we requested NSPs to list all the weather stations within their networks. In response to submissions, we have added the option for NSPs to identify weather stations that are not representative of the weather conditions experienced by the NSP and explain why this is the case.

9.2.2 Reasons for position

The list of weather stations provided by NSPs will be used in conjunction with weather data we have collected from the BOM. The data we have collected includes peak wind gusts and daily temperature data for each weather station. Other data available from the BOM may also be included in our analysis.

CitiPower and Powercor submitted that taking an average across multiple weather stations may smooth out the occurrence of extreme weather events and fail to account for the impact of extreme weather in particular zones and possibly over-account for weather events that have occurred in zones where there is low customer density or few network assets.¹⁰⁶

To address the issue of incorporating weather events where there is low customer density or few network assets, we have added the requirement for NSPs to identify and explain why a weather station is not representative of the weather conditions experienced by the NSP. Further, our analysis will not necessarily involve taking a simple average of temperature and wind across all weather stations. We will be using the data to identify extreme weather events such as consecutive days of extreme heat days that occurs across several weather stations.

Where we consider the inclusion of a particular weather station will distort our analysis of the overall weather conditions experienced by a NSP, we will remove the data from our operating environment analysis.

¹⁰⁶ CitiPower and Powercor Australia, *Submission to AER on Draft Regulatory Information Notice for Economic Benchmarking*, 18 October 2013, p. 14.

9.3 Rural proportion

We have removed the rural proportion requirement for TNSPs. TNSPs operate long lines predominantly in rural areas so the urban proportion is not expected to have a material impact on costs.

9.4 Other operating environment factors

Other operating environment factors include density measures for DNSPs, variability of dispatch, altitude and concentrated load distance for TNSPs and standard vehicle access and line length for all NSPs.

9.4.1 AER position

We have not made any significant changes to our other operating environment factors.

9.4.2 Reasons for position

We consider submissions received on standard vehicle access and backyard reticulation below.

Standard vehicle access

Powerlink requested clarity for the definition of standard vehicle and noted its standard vehicle was a 4WD.¹⁰⁷

Standard vehicle access is an important variable in identifying the terrain in which a network operates. Difficult terrain may lead to additional maintenance costs where standard vehicles or equipment cannot be used. As with our vegetation management related variables we have reduced the back cast requirement to one year if the NSP does not collect data on this variable. We have also amended the definition of standard vehicle access to include areas accessible by two wheel drive vehicles.

Backyard reticulation

Due to legislative requirements ActewAGL has a backyard reticulation system and must access residential backyards and business properties for planned maintenance. ActewAGL submitted that backyard reticulation is an operating environment factor that should be taken into account and proposed the proportion of lines or poles in backyards due to legislative requirements should be considered.¹⁰⁸

We consider legislated backyard reticulation could lead to higher observed costs. However, we consider measuring the impact of this legislative requirement to be best measured qualitatively. This is consistent with our position on bushfire legislative risk where the extent of the increase in costs due to legislation would not be captured in a simple measure of the km line or number of spans where the legislative requirement exists. Any submission that sets out the qualitative and quantitative impact of legislative requirements on a NSPs costs will be considered in our analysis of the economic benchmarking results.

¹⁰⁷ Powerlink, *Powerlink Response - AER Draft Benchmarking RIN*, 18 October 2013, p. 5.

¹⁰⁸ ActewAGL, *Response to AER draft regulatory information notice for economic benchmarking*, 18 October 2013, p. 1.