Better regulation

Explanatory statement

Regulatory information notices to collect information for economic benchmarking

September 2013

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Amendment record

Version	Date	Pages

Contents

Shortened forms

Shortened term	Full title
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
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
MEU	Major Energy Users
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
PIAC	Public Interest Advocacy Centre
RAB	Regulatory asset base
RIN	Regulatory information notice
RIO	Regulatory information order
SAIDI	System average interruption duration index
SIAFI	System average interruption frequency index
STPIS	Service target performance incentive scheme
TFP	Total factor productivity
TNSP	Transmission network service provider
TOU	Time of use

Introduction

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, which commenced in late 2012, we released draft Expenditure Forecast Assessment Guidelines (Guidelines) in August 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 two new benchmarking techniques that we intend to use in conjunction with our existing assessment techniques. The first is developing a nationally consistent reporting framework that will allow us to benchmark expenditure at the disaggregated category level, referred to as category analysis.

The second is economic benchmarking, which will allow us to analyse the efficiency of network service providers (NSPs) over time and compared to their peers. Economic benchmarking will also allow us to develop a top down forecast of expenditure and estimate productivity change. The draft information notices set out in the attachments to this statement relate specifically to economic benchmarking.

As we have noted in consultation with stakeholders, we need to collect a large amount of data from NSPs to implement these new benchmarking techniques. We are aware that some information we intend to collect in both benchmarking workstreams is similar and may seem duplicative. However, the data requirements are different. For economic benchmarking we require aggregated data because we will use it for top down analysis. The category analysis data is disaggregated because we will be using it for lower level comparisons. In any case, NSPs will not need to provide data for both benchmarking workstreams simultaneously—we require economic benchmarking data in February 2014 and category benchmarking data in May 2014.

We have been consulting extensively with stakeholders in relation to the process, techniques and data requirements associated with benchmarking. Following the publication of our issues paper in December 2012, we conducted a series of workshops between March and June 2013. For economic benchmarking we have sought comments from interested parties in response to preliminary regulatory information notice (RIN) templates that we provided to stakeholders in July 2013 and again in August 2013. Consistent with the preliminary RIN templates, the draft economic benchmarking RIN and templates require NSPs to provide data for several inputs, outputs and environmental factors.

The aim of these economic benchmarking data templates is to collect a historical data set that will allow us to provide the public with consistent, transparent data. This will form the basis for our first benchmarking report in September 2014. 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 will also use the benchmarking data in annual benchmarking reports and to assess forecast expenditure, as required by the National Electricity Rules (NER).

The accompanying draft economic benchmarking RIN commences the formal process of consultation with interested stakeholders before we issue the final RIN in November 2013. Economic benchmarking data required in the final RIN is due from NSPs in February 2014. As we stated in our draft explanatory statement for the Guidelines, we will have regard to principles when applying all of our assessment techniques. To assist this assessment, once we have received the data, we will conduct an extensive testing and validation process. The testing and validation process will involve further consultation with stakeholders and provide opportunity for cross submissions on each NSP's benchmarking data.

Following this process, we will release the benchmarking model(s) and an accompanying issues paper for consultation. NSPs can then comment on the benchmarking results before we prepare and publish the annual benchmarking report in September 2014.

We have reviewed all submissions from NSPs on our preliminary RIN templates, which raised several key issues. In particular, most NSPs were concerned with auditing requirements, the ability to provide historical data, physical metrics and separating opex and assets into common services. NSPs have raised some legitimate issues and the draft RIN and templates have been amended to reflect many of the comments provided by stakeholders. However, NSPs in some instances did not substantiate their concerns; they tended to be high level. In the absence of specific reasoning and suggestions, it would be difficult to justify a change in our approach.

If, however, NSPs can articulate specific concerns and propose solutions to these concerns, we may be able to reach common ground on data requirements. We are open to alternative methods of defining terms, constructing measures and assurance requirements proposed by NSPs if they are reasonable and substantiated.

Accordingly, in response to the draft RIN and templates, we request NSPs to outline their specific concerns for relevant data items and to propose a solution or amendment. Where NSPs consider it is not possible to provide actual data in response to a data requirement, we would appreciate if NSPs could outline a method for how they could provide a reasonable estimate and the basis for this method. We are mindful that we are asking for a large data set. If it is not possible to provide actual data, we expect NSPs to provide estimates accompanied by reasons why the estimates are appropriate. We will hold a workshop on 9 October 2013 and have bilateral meetings to discuss these issues. We are also publishing this explanatory statement and the draft RIN to receive comments from all stakeholders who attended economic benchmarking workshops and the broader public.

Next steps

A summary of the key indicative dates for upcoming RINs for both benchmarking workstreams is as follows.

Date	Economic benchmarking	Category analysis
15 November 2013	Issue final RIN	
29 November 2013		Issue draft RIN
16 February 2014	RIN responses due	
February 2014	Commence data testing and validation	Issue final RIN
April 2014	Data published on AER website Cross submissions on data sought	
May 2014	Cross submissions due Audit reports due	RIN responses due

Request for submissions

Pursuant to section 28J of the National Electricity Law, we invite written submissions on the draft RIN. Stakeholders are allowed 20 business days to make submissions. The closing date and time for submissions is 5 pm Australian Eastern Daylight Time on Friday, 18 October 2013.

Submissions should be sent electronically to expenditure@aer.gov.au. We prefer that all submissions sent in an electronic format are in Microsoft Word or other text readable document form. Alternatively, submissions can be sent to:

Chris Pattas
General Manager – Network Operations and Development
Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website at www.aer.gov.au. For further information regarding the AER's use and disclosure of information provided to it, see the ACCC/AER Information Policy, October 2008 available on the AER website.

Enquiries about this paper or about lodging submissions should be directed to the Network Operations and Development Branch of the AER on (03) 9290 1444.

1 General concerns

Stakeholders have raised a number of matters in response to our preliminary templates for economic benchmarking. In this chapter we consider general matters raised on process, definitions, auditing and historical information. The remaining chapters consider specific issues raised with the templates themselves.

1.1 Process Issues

1.1.1 AER position

We have extended the timeframe for NSPs to provide audited data in response to the RIN. This is designed to reduce the burden on NSPs by providing additional time for the auditing process. Where it is not possible to provide audited data in response to the RIN by February 2014, estimates of data may be provided on a 'best endeavours' basis, together with Director signoff to this effect. NSPs can then provide auditors' reports in relation to the information provided in response to the RIN by mid May 2014. However, given the significant consultation process to date, we also expect that NSPs are already making arrangements to provide the data we require. We expect all relevant sections of the template to be completed in the February 2014 responses.

In addition, we have amended the RIN templates to provide further guidance to NSPs in relation to when they are not required to provide information in response to the RIN. Going forward, NSPs will be required, on an annual basis, to update the RIN templates and provide audited data for the most recent regulatory year.

1.1.2 Reason for AER position

Timeframe

A number of NSPs raised issues with process associated with issuing and responding to the RIN. For example, some NSPs were concerned that the AER's proposed timeframe would be difficult to meet.[1] Some NSPs noted it would be preferable if RINs could be streamlined to avoid duplication and redundant information requirements. Grid Australia and Essential Energy considered a general regulatory information order (RIO) was a more appropriate instrument than a RIN for this process.[2] Grid Australia also requested the opportunity to inform any interpretation of benchmarking results to ensure we appropriately account for environmental factors between transmission network service providers (TNSPs).[3]

We recognise we are requiring NSPs to complete multiple RINs and that this can be burdensome. However, this is necessary to implement and consult on our assessment techniques. We consider this process is in the long term interests of consumers. The draft Expenditure Forecast Assessment (EFA)

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1 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 7; Grid Australia, *Grid Australia comments on AER preliminary regulatory information notice template*, 23 August 2013.; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

2 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 7; Grid Australia, *Grid Australia comments on AER preliminary regulatory information notice template*, 23 August 2013.

3 Grid Australia, *Grid Australia comments on AER preliminary regulatory information notice template*, 23 August 2013.

explanatory statement sets out the indicative timeframes for information reporting requirements, subject to the modifications outlined below.[4]

In terms of the instruments we use, the NEL permits us to use either RINs or a RIO to collect the economic benchmarking data.

We have decided to issue RINs for both our category analysis and economic benchmarking data requirements as in interim step. We consider the additional consultation requirements associated with a RIO would delay the process given the consultation we have had with NSPs to date. We have already undertaken extensive consultation in relation to the economic benchmarking RINs, including workshops with stakeholders in relation to the data requirements and providing preliminary draft RINs to NSPs in July 2013 and August 2013. However, while this is a RIN process, we are publishing this statement and the draft RIN to receive comments from all stakeholders who attended economic benchmarking workshops and the broader public.

Going forward, our aim is to consolidate all ongoing reporting requirements (economic benchmarking, category benchmarking and annual reporting) into a single RIO in 2015.

The draft RIN requires NSPs to continue providing the data in the RIN templates to the AER on an annual basis. NSPs must update the templates to provide the economic benchmarking data for the most recent regulatory year. Because the annual data will be current, it must not be based on estimates. The exception to this is data for the Assets (RAB) worksheet because the split of assets may necessarily be based on estimation. Further, if a NSP chooses to modify its cost allocation method (CAM) in the future, it will be necessary for the NSP to provide the back cast financial data set in accordance with the new CAM, as set out in the *Cost Allocation Guidelines*.[5] Once the consolidated RIO has been established, NSPs will no longer be required to separately report economic benchmarking data on an annual basis.

In relation to the proposed timetable, we have considered how we can reduce the impact of audit requirements on the provision of data by NSPs. Rather than requiring NSPs to provide audited data in February 2014, we propose the following amended timetable:

- mid February 2014 – final RIN responses due with Director sign-off (which state that best endeavours have been undertaken to provide estimates of 'missing' data)
- mid February to mid April 2014 – the AER will review the data that has been provided by NSPs. We will also liaise with NSPs to fill gaps in the data series by assisting NSPs in relation to the possible ways of best estimating missing data; progressively refine the data by identifying errors and/or different assumptions used by NSPs in responding to the final RIN; develop a preliminary economic benchmarking model; preliminary implementation of the model which may provide a further 'sanity check' of the data and may assist in identifying errors and differences in assumptions made in responding to the RIN
- mid April 2014 – data posted on AER website. At this time, the AER will call for 'cross submissions'. Interested parties may make submissions on other NSPs' data. During this time, NSPs are requested to commence auditing the data

4 AER, *Explanatory statement - draft expenditure forecast assessment guidelines for electricity transmissions and distribution*, 9 August 2013, p. 71.

5 AER, *Electricity distribution network service providers Cost allocation guidelines*, June 2008, s. 4.2; AER, *Electricity transmission network service providers Cost allocation guidelines*, September 2007, s. 4.2.

- early May 2014 – cross submissions on data due
- mid May 2014 – auditors' reports due.

Following this process, we will release the benchmarking model(s) and an accompanying issues paper for consultation. NSPs can then comment on the benchmarking results before we prepare and publish the annual benchmarking report in September 2014.

Spreadsheet inputs

Ergon Energy asked how it should complete the templates when inputting the data would be inappropriate, such as in cases where an expenditure category is not relevant to standard control services or network services.[6] Ergon Energy also suggested changes to some worksheet titles.[7] We have reviewed the RIN templates and added instructions at the top of each worksheet to clarify the requirements where these may have been ambiguous. These instructions clarify the requirements of the templates and the circumstances when data does not need to be provided.

While we appreciate the suggestions from Ergon Energy, we have decided not to amend worksheet titles because we consider they are clear enough and no other NSPs raised concerns about them.

1.2 Definitions

1.2.1 AER Position

We have clarified a number of definitions that may have been unclear.

For the scope of service definition, we are removing the requirement for network services to be disaggregated by the DNSPs' current opex categories because we recognise this may not be feasible for all businesses. The DNSPs will still be required to provide the total opex for network services and disaggregated opex for standard control services and alternative control services and the assumptions used to estimate network services opex.

We have created a new network services variable under '3.2 Opex consistency'. We note network services is a subset of standard control services. However, other variables in '3.2 Opex consistency' may be either standard control services or alternative control services depending on the service classification in the previous distribution determination.

We will require DNSPs to provide the relevant information for these services if they are classified under direct control services in their jurisdiction. If a DNSP undertakes these services but they are not classified as a direct control service in their jurisdiction, they will not be required to provide data.

1.2.2 Reasons for AER position

Several NSPs submitted that certain definitions require clarification and hence it is desirable for the AER to provide clear definitions that will be interpreted consistently by NSPs and minimise auditing requirements.[8] For example, a number of NSPs noted it was unclear which of three possible 'year'

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6 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

7 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

8 Energex, *Draft economic benchmarking templates - Energex response*, 26 August 2013; Ergon Energy, *Response to RAB allocation questions*, 5 August 2013; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 4; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 1; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, pp. 1–2.

definitions they must report data against, noting that it would be unlikely they could provide data for a different year.[9]

Scope of service definition

It is apparent from submissions that the draft EFA explanatory statement and preliminary draft RIN were not clear on how we required expenditure and assets split into network services, standard control services and alternative control services.[10]

In the explanatory statement for the draft EFA guidelines we considered a common coverage of services was required to undertake economic benchmarking. Not all services are classified in the same way across different jurisdictions. For example, customer funded connections, are classified as unregulated in New South Wales, as an alternative control service in Queensland and as a negotiated service in South Australia.[11] We consider an appropriate comparison point to be network services which are classified as part of standard control services across all states and territories.

We have restructured the RIN templates to clarify how distribution services are to be disaggregated. To account for differences in the classification of services across jurisdictions we will still require some information relating to non-network services.

General

We have reviewed the definitions and made changes where appropriate. Attachment A includes all definitions we have modified. In terms of the definition of 'year', we require NSPs to report in accordance with regulatory years only.

1.3 Auditing and Director certification

1.3.1 AER position

While we are open to refinement of the position on auditing of economic benchmarking data, our current position for the draft RIN remains that all requested data should be audited. We have allowed some additional time for auditing and have ensured the draft RIN contains appropriate guidance for auditors. We have drafted the RIN in a manner that we consider does not ask NSPs' Directors to take on excessive or unreasonable risk. In consultation with audit practitioners, we have also made some amendments to our position from the draft EFA explanatory statement. That is, our current position is to require reasonable (positive) assurance on financial information, in accordance with ASA 805 and negative assurance on non-financial information in accordance with ASAE 3000. We will also require negative assurance in accordance with ASAE 3000 where financial or non-financial information is estimated. As noted in section 1.1, we require ongoing annual data to also be audited.

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9 Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 1; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 4; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

10 Energex, *Draft economic benchmarking templates - Energex response*, 26 August 2013; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Jemena Electricity Networks, *Response to revised draft economic benchmarking templates*, 20 August 2013; Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 7; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 4.

11 AER, *Explanatory statement – Draft expenditure forecast assessment guidelines for electricity transmission and distribution*, p. 94.

1.3.2 Reasons for AER position

The majority of NSPs raised concerns with the AER's proposal to require auditing or Director certification of economic benchmarking data.[12] Concerns varied, but generally related to the following:

- the burden it would impose on NSPs in terms of time and resources
- inability to provide, or difficulty of providing, historical or estimated data to an auditable standard
- the inappropriateness of auditing requirements
- risk for Directors associated with signing off on historical data that was collected for a different purpose, with different reporting requirements and potentially under different management or ownership arrangements
- a need for clarification from the AER and further consultation.

Some submissions, however, supported auditing for all financial and non-financial information used for benchmarking against a clearly defined standard.[13] Some other NSPs did not comment on this issue.[14]

CitiPower, Powercor and SA Power Networks, while supporting the need for auditing, suggested the AER consult with recognised audit practitioners regarding the level of audit comfort that can be provided for historical data. A standard or guideline could then be published and used as a reference, which auditors could provide an opinion on.[15] SP AusNet suggested an 'Agreed Upon Procedures' engagement would provide an appropriate level of comfort to the AER, at a lower cost to NSPs.[16]

Following consultation with audit practitioners, we believe that our position to require audit assurance is appropriate. As we noted in our draft EFA explanatory statement, it is our priority to gather robust data and independent auditing is necessary to provide an appropriate level of assurance.[17] While it is clear that some NSPs have concerns with auditing, in general, those NSPs did not substantiate their concerns. Rather than providing specific issues and proposing solutions, concerns were at a high level. We acknowledge that auditing will impose an additional burden on NSPs, but consider the benefits of having robust data that has been audited to be significant, and outweigh any additional burden on NSPs. Further, some NSPs consider auditing is appropriate, or did not raise concerns.

We maintain that auditing is necessary and appropriate. We are not satisfied that an 'Agreed Upon Procedures' engagement is appropriate in the absence of specific guidance from NSPs on the review procedures that would be performed. However, we have sought advice from audit practitioners on the

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12 Electranet, *Response to revised draft economic benchmarking templates*, 20 August 2013; Energex, *Draft economic benchmarking templates - Energex response*, 26 August 2013; Networks NSW, *Response to AER regarding benchmarking data*, 13 September 2013, pp. 1, 4, 6; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Grid Australia, *Grid Australia comments on AER preliminary regulatory information notice template*, 23 August 2013.; SP AusNet, *Response to revised draft economic benchmarking templates*, 22 August 2013; ; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, pp. 3–4; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 2.

13 Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 3; CitiPower, Powercor Australia and SA Power Networks, Submission to the AER on the revised draft data list for economic benchmarking, 16 August 2013, p. 2.

14 For example, Transgrid, Aurora and Jemena.

15 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 2.

16 SP AusNet, *Response to revised draft economic benchmarking templates*, 22 August 2013.

17 AER, *Explanatory statement – Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 74.

most appropriate audit requirements for the data we are requiring NSPs to provide and provided NSPs with additional time to comply with the requirements.

Based on advice from audit practitioners, we have made some amendments to our position from the draft EFA explanatory statement. That is, our current position is to require reasonable (positive) assurance on financial information, in accordance with ASA 805 and negative assurance on non-financial information in accordance with ASAE 3000. We will also require negative assurance in accordance with ASAE 3000 for financial or non-financial information that is estimated. We do, however, agree with CitiPower, Powercor and SA Power Networks that auditors will need a reference to provide an opinion on. We have included guidance in the draft RIN but we are interested in NSPs' views on this. We also agree that further consultation on auditing could be beneficial and intend to discuss auditing in a workshop on 9 October 2013.

Regarding Director sign off, we do not consider we are asking Directors to take on excessive risk. For clarity, we require Directors to certify that a NSP has complied with the requirements of the RIN. However, where some amount of estimation is required or assumptions are made to comply with the RIN, we cannot expect Directors to certify that all data is accurate. Rather, we have drafted the RIN in a way that acknowledges these uncertainties. For example, Directors would certify that to the best of their knowledge, actual data is true and accurate, but where the NSP has relied on assumptions or used estimates, they are reasonable and are able to be substantiated on the basis of the information that is available to the NSP.

CitiPower, Powercor and SA Power Networks also raised a concern that we were suggesting the NSPs could provide data prior to Board approval.[18] The draft EFA explanatory statement may have been unclear on this point. We did not intend to suggest that NSPs could submit data without any Board sign off. Rather, as noted above, we will accept data that an NSP's Board has approved prior to the audit of that data. If the audit results in changes to the data, the NSP would resubmit the data; otherwise the NSP would submit the audit report(s). We consider this will streamline the process associated with providing the data while also giving NSPs adequate time for auditing.

Ergon Energy and SP AusNet queried whether disaggregated data requires auditing if it reconciles to data previously provided or audited, and whether reconciliation with previously provided data will also require auditing.[19] The ENA submitted that where disaggregation of data will impact benchmarking results, the disaggregation should be audited against a defined standard.[20] For clarity, where a NSP has previously provided to the AER in response to a RIN financial data audited to the same standard we are requiring for the draft economic benchmarking RIN, it is not necessary to audit it again. However, if this previously audited and supplied data is disaggregated for the purposes of the draft economic benchmarking RIN, the disaggregated data and reconciliation with the previously audited and supplied data must be audited.

1.4 Historical data

1.4.1 AER position

Our position remains that NSPs must provide a back cast time series for 10 years. We are requesting NSP to use their best endeavours to estimate data according to assumptions where actual data is not

18 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 2.

19 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; SP AusNet, *Response to revised draft economic benchmarking templates*, 22 August 2013.

20 Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 3.

consistent with the AER's requirements. The draft RIN contains some guidance on how NSPs should develop these assumptions. NSPs must clearly set out their interpretations and assumptions used and provide supporting documentation. We will publish this information for public scrutiny and peer review as suggested by CitiPower, Powercor and SA Power Networks.

1.4.2 Reasons for AER position

The majority of NSPs raised concerns with the AER's requirement for NSPs to provide 10 years of back cast data.[21] Generally, the concerns related to:

- the burden it would impose on NSPs in terms of time and resources
- inability to provide, or difficulty of providing, historical data due to, among other things, changes in IT systems
- data availability, quality and reliability
- inappropriateness of estimating data
- a back casting approach being inconsistent with the AEMC's TFP review.

Aurora submitted that the classification of some of its data is inconsistent with the AER's requirements, but would allocate it according to a set of assumptions supported by documentation.[22]

Some NSPs considered allowing NSPs to estimate data using their own assumptions would adversely affect data quality and consistency. Regardless, they considered that NSPs should be able to make their own assumptions in order to estimate data.[23] Ergon Energy considered the RIN should include a clause for non-provision of data where NSPs have never collected certain variable data sets (similar to Annual Performance RINs).[24]

CitiPower, Powercor and SA Power Networks considered the AER should make all NSPs' interpretations or applied assumptions publicly available. They submit that this would ensure appropriate assessment of quality and consistency of data over time and across NSPs. CitiPower, Powercor and SA Power Networks also noted that auditors may not be able to assess the reasonableness of assumptions – they may be able to assess only whether a NSP has applied the assumptions. It would be the AER who must assess the appropriateness of the documented method.[25]

We agree that any assumptions made by an NSP when responding to the RIN should be published. We consider that transparency and public scrutiny will encourage NSPs to develop reasonable assumptions when constructing data on a best endeavours basis in response to the RIN. We also

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21 Electranet, *Response to revised draft economic benchmarking templates*, 20 August 2013; Energex, *Draft economic benchmarking templates - Energex response*, 26 August 2013; Networks NSW, *Response to AER regarding benchmarking data*, 13 September 2013, pp. 1, 4, 7; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.; Grid Australia, *Grid Australia comments on AER preliminary regulatory information notice template*, 23 August 2013; SP AusNet, *Response to revised draft economic benchmarking templates*, 22 August 2013; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 4; Jemena, 20 Aug 2013; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 2; Transgrid, *Response to revised draft economic benchmarking templates*, 27 August 2013.

22 Aurora Energy, *Response to revised draft economic benchmarking templates*, 20 August 2013.

23 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 5.

24 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

25 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 2.

acknowledge that allowing NSPs total freedom to develop assumptions and estimates could adversely impact on data consistency and quality so we will provide some guidance. In general, when estimating data, NSPs should assume:

- the estimate should be based on a causal link between the raw data and the data we require, and
- if no causal link can be established without undue cost and effort, the most appropriate estimate should be used, and NSPs should explain why it is the most appropriate estimate. In explaining why it is the most appropriate estimate, NSPs should outline other options considered and why they were not the most appropriate estimate.

We consider that under a review engagement an auditor will be able to derive a conclusion as to whether the methodology and assumptions applied to a given data set is not unreasonable (negative assurance). The AER would need to assess the appropriateness in addition to the audit, based on the level of knowledge obtained from receipt of all NSP estimated data.

Beyond providing additional guidance on assumptions, we are not convinced that it is unreasonable for us to require back cast data. We acknowledge that some NSPs may not have the data in the form we require it, but consider reasoned estimates are an appropriate alternative. Back casting or estimating may not be a straight forward exercise, but we are asking NSPs to use their best endeavours to fill data gaps.

Similar to concerns raised with auditing, many NSPs generally did not explain their concerns with back casting in detail, or suggest how we could amend the RIN to mitigate the perceived problems. We consider that if NSPs can estimate forecasts, it should also be possible to estimate past data in accordance with our requirements based on raw data and substantiated, reasonable assumptions. For example, if NSPs' IT systems have changed, we would expect that NSPs would access previous systems to provide the information. We note that at a minimum the *Corporations Act 2001* requires companies to retain financial records for 7 years after relevant transactions are completed, regardless of the systems in place.[26] Compliance with RIN requirements is essential to the AER being able to perform its functions under the NEL and NER, so we expect that NSPs would take all the necessary steps to provide the information requested.

We consider that it is appropriate to request a broad range of data for economic benchmarking, some of which not all NSPs will be able to provide. Some of the data may explain differences in relative productivity. Further, much of the data will be of interest to other stakeholders undertaking their own benchmarking analysis. By requesting and publishing this data, stakeholders will be able to conduct sensitivity analysis of economic benchmarking results using the data and develop their own models. Publishing more data will give stakeholders more ability to conduct their own analysis and will ensure that a broader and longer series of data will be available for analysis.

We are also not persuaded that our approach is inconsistent with the findings of the AEMC's TFP review. While the issues raised in that review are related, they are also distinct. The AEMC Review looked at productivity or TFP-based regulation which bases the price or revenue cap decision, typically the setting of the X factor, on productivity estimates. The current exercise involves using economic benchmarking as one of a number of tools to inform building block decisions. Importantly, the AEMC's comments regarding data availability and quality also related to data in the public domain or used in previous regulatory decisions. The current exercise involves collecting more consistent data directly from NSPs. We will consider the robustness of the data in the testing and validation

26 *Corporations Act 2001*, s. 286.

process. Our views on the robustness of the data will determine how we have regard to economic benchmarking techniques in forming a view about expenditure.

As we noted in the draft EFA explanatory statement, the Australian Government considers that it is appropriate to use economic benchmarking techniques and that it is important that we are provided with the required information.[27] Rule changes by the AEMC since the previous TFP review also support greater use of benchmarking as does the recent PC Inquiry. Submissions from customer groups also strongly support us collecting information to conduct benchmarking analysis.[28] The Australian Energy Market Operator (AEMO) also supports a nationally consistent reporting framework that allows for improved benchmarking measures across network businesses.[29] As a result, we intend to collect the data that is needed to undertake economic benchmarking.[30] We also think it would be presumptuous to form an opinion on the quality and reliability of back cast data until we have collected it and tested its use.

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27 Australian Government, *The Australian Government response to the productivity commission inquiry report – Electricity Network Regulatory Frameworks*, June 2013, pp. i-ii, 3-9.

28 For example, Major Energy Users, *Australian Energy Regulator Better Regulation Expenditure Forecast Assessment Guidelines – Comments on the Issues Paper – Submission by The Major Energy Users Inc*, March 2013, pp. 18-21; Public Interest Advocacy Centre, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, pp. 10-16.

29 AEMO, *Response to AER draft expenditure forecast assessment guidelines for electricity transmission and distribution economic benchmarking templates*, 29 August 2013, p.1.

30 AER, *Explanatory statement – Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 74.

2 Revenue

For 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 a 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. [31]

2.1.1 AER Position

We have clarified the information requirements in the revenue section, as set out below.

2.1.2 Reasons for AER position

NSPs raised a number of minor queries in relation to revenue. These are considered in the following paragraphs. Where necessary, we have amended the templates to remove ambiguity.

Energex questioned whether revenue numbers should include or exclude under and over recoveries.[32] The revenue requirements should include under or over recoveries of revenue against forecasts. This is because the exclusion of over or under recoveries would add an unnecessary level of complexity to the templates. Further, for NSPs under price caps, defining and calculating over or under recoveries could be problematic. We have clarified this in the data templates.

There were some questions regarding the revenue effects of incentive schemes. TransGrid questioned whether we intended Efficiency Benefit Sharing Scheme (EBSS) payments to be included in sections 2.1 and 2.2 as well as section 2.3 of the revenue worksheet.[33] TransGrid also questioned whether payments from incentive schemes preceding the EBSS should be included in revenue.[34] Ergon Energy considered it was not possible to back cast revenue or penalties against incentive schemes not relevant to a NSP historically.[35]

We are requiring NSPs to include the revenue increments or decrements from all incentive schemes (including those preceding the EBSS, where applicable) in reported revenue amounts in sections 2.1 and 2.2 of the revenue worksheet. This is because the removal of the effects of incentive schemes would create an additional, unnecessary burden. The effects of incentive schemes on revenues is already separately requested. In circumstances where certain incentive schemes were not historically relevant to a NSP, the amount of revenue or penalties would be zero. The templates now clarify this.

Endeavour Energy asked whether ‘revenue from other sources’ is intended to cover DUOS only.[36] Along similar lines Essential Energy questioned where ancillary network services/miscellaneous and monopoly revenue should be reported.[37] ElectraNet also requested clarification on what is to be included in ‘revenue from other sources’.[38] The revenue worksheet is designed to collect only direct

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31 For further explanation of the billed outputs specification see: Economic Insights Pty Ltd, *Economic Benchmarking of Electricity Network Service Providers: Report prepared for Australian Energy Regulator*, 25 June 2013, Denis Lawrence and John Kain, p. 6.

32 Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

33 Transgrid, *Response to revised draft economic benchmarking templates*, 27 August 2013.

34 Transgrid, *Response to revised draft economic benchmarking templates*, 27 August 2013.

35 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

36 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 4.

37 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 7.

38 Electranet, Excel workbook, *TNSP economic benchmarking data template Electranet comments*, 20 August 2013.

control network services revenues (for DNSPs) and prescribed services revenues (for TNSPs). Where revenues do not align with the revenue categories requested they are to be reported in the 'other' categories.

Endeavour Energy queried whether the AER will account for changes in the classification of revenue over time and between jurisdictions.[39] We have requested revenue be broken down by the classification of distribution services in the templates. This will provide information on the effect of changes in the classification of services on revenue over time and across jurisdictions. We consider that going to a further level of detail than this could be overly burdensome and unnecessary. The revenue breakdowns are intended to be used to weight outputs under a billed output specification as part of our sensitivity analysis. We do not expect that changes in the classification of services would greatly affect these weightings.

The point has also been raised that consistent comparison of NSPs' revenue would require specification of how revenues related to feed in tariffs, jurisdictional taxes or charges and GST are treated. We have requested the revenue information in the templates for the potential application of a billed outputs specification. Under this output specification revenues are used to weight outputs of NSPs. It is not expected that taxes, however reported, will affect these weightings as taxes are typically pro-rated across the charge. Feed-in tariffs from embedded generation may have an effect on the weightings and consequently comparability. To mitigate this issue we have specified that revenue is to be reported net of the effect of feed-in tariffs. This will ensure consistent treatment of feed-in tariffs across jurisdictions.

Endeavour Energy also considered that unmetered revenue would be difficult to provide due to the lack of a specific tariff for such customers over the specified period.[40] We accept that in some cases specific revenue requirements might be difficult to report. However, we consider that the overall revenues should reconcile to previous regulatory accounts and financial statements. These should provide an appropriate basis for the estimation of historical revenues where this information is not available.

TransGrid suggested that it would be more appropriate for section 2.3 to refer to 'incentive' rather than 'EBSS'.[41] We have made this change to the transmission RIN.

Endeavour energy also requested that we confirm whether controlled load lives in the available categories of off-peak or non-TOU.[42] We reviewed Endeavour Energy's controlled load tariffs. Endeavour has two controlled load tariffs under which specified appliances are controlled such that electricity to power them is only available for restricted periods. Under these tariffs switching times are managed to minimise network investment and meet customer needs for the load being controlled.[43] We consider that these times would not be times of peak electricity usage, and hence revenue earned from the controlled load tariffs should be reported in the off-peak category. We have amended the definition of off-peak to clarify this.

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39 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p.4.

40 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 5.

41 Transgrid, *Response to revised draft economic benchmarking templates*, 27 August 2013.

42 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 4.

43 Endeavour Energy, *Network price list 2013/2014, effective 1 July 2013*, 2013, p.5.

3 Opex

3.1 Opex categories

The opex categories will be used to help us understand the drivers for changes in opex and efficiency. For a NSP the disaggregation of opex into the categories used by NSPs will not impact the overall measurement of efficiency in economic benchmarking because the proposed specification uses a total measure of opex.

3.1.1 AER position

To allow for a comparison of opex through time and across DNSPs/TNSPs, the total opex must be calculated on as consistent a basis as possible. To address the issue of consistency through time we will require the NSPs to provide all opex data calculated in accordance with their current opex categories and CAMs. Section '3.1 Network operating and maintenance costs' has been renamed to '3.1 Opex – current categories and cost allocations' to reflect this.

NSPs that have not changed their opex categories and CAMs can provide actual disaggregated historical data. NSPs that have changed their opex categories and CAMs are requested to provide disaggregated historical estimates based on their current opex categories and CAMs. Further, these NSPs will have to separately report their opex categories for each time period. Table 3.1 provides an example of the reporting requirements where three sets of opex categories have been used by a hypothetical DNSP.

Table 3.1 Example of opex category reporting requirements where opex categories have changed over time

Variable code	Variable
	3.1 Opex categories
	3.1.1 Opex – current categories and cost allocations (for the whole period)
DOPEX0101	[Opex category 1]
DOPEX0102	[Opex category 2]
DOPEX0103	[Opex category 3]
	3.1.2 Opex categories and cost allocations (only for 2008– 2010)
DOPEX0101A	[Opex category 1 2008–2010]
DOPEX0102A	[Opex category 2 2008–2010]
DOPEX0103A	[Opex category 3 2008–2010]
	3.1.X Opex categories and cost allocations (only for 2003–2007)
DOPEX0101B	[Opex category 1 2003–2007]
DOPEX0102B	[Opex category 2 2003–2007]
DOPEX0103B	[Opex category 3 2003–2007]

In this example the NSP will not need to separately report the opex categories and cost allocations for 2011–2012. The data collected under 3.1.1 will be consistent with the categories and allocations applied in 2011–12.

3.1.2 Reasons for position

Opex categories across businesses

Some submissions noted using each NSP’s own opex categories, which may vary across businesses, would not allow for an appropriate comparison of opex across businesses.[44] As discussed above the opex categories themselves do not impact on the measurement of opex efficiency. This data will be used to help us understand what is driving a NSP's productivity results. We are aware that differences in the opex categories may limit the basis of comparison between NSPs of the drivers of change in opex efficiency.

We will adopt standard opex categories in the category analysis RIN. These will be based on the new opex categories proposed in our category analysis work stream. At this stage we are still consulting on the new opex categories and we do not consider it appropriate to backcast based on a standard set of categories that have not yet been finalised.

Opex categories across time

Some NSPs submitted that opex categories can vary over time due to different cost allocation methodologies or changes to service classification.[45]

We consider a consistent as possible comparison of total opex across time is needed for our economic benchmarking model and we have amended the template to reflect this requirement. Where opex categories and cost allocation methods have changed, we are requesting businesses to backcast this information based on their current opex categories and cost allocation methods. These businesses will need to also provide their historical opex categories in the format shown above (refer to Table 3.1). As discussed, the primary focus is for total opex to be provided by NSPs on a consistent basis as possible. The disaggregated opex categories will assist us in our opex driver analysis.

Where a DNSP is unable to backcast its current opex categories and CAMs, the DNSP is required to provide an estimate of its total opex for each regulatory year based on the likely effect of its changes in CAMs.

We recognise that some businesses may need to estimate historical opex categories where they have changed over time. Where estimations have been made, NSPs are required to explain and justify the estimations.

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44 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 4; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, pp. 1–2; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

45 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 5; Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

3.2 Other opex worksheet issues

3.2.1 AER position

As discussed in the scope of service definition section, we have made amendments to the opex worksheet. As a result of these changes we have added in a network services variable, the DNSP is required to provide the total network services opex for each year and the assumptions used to estimate the network services from standard control services.

To provide extra clarification on how NSPs should input opex data, we have included instructions at the top of the opex worksheet. These specify where NSPs are not required to provide data.

In response to submissions we have removed DOPEX0207 'Opex for expenditure for activities by contractors' and DOPEX0208 'Opex for expenditure for activities by related parties'.

We have amended the definition for the previous variable "Opex for high voltage customers opex estimate" to include both actual and estimated opex. The NSP should indicate whether the costs are estimated or actual costs. If the costs are actuals, the NSP must also note if the costs have been included in "3.1 opex categories".

For opex related to metering we amended the opex definition to be consistent with our general definition so only opex related to metering types 5–7 are to be included.

3.2.2 Reasons for position

Some NSPs submitted that they may be unable to distinguish the costs between contractors and related parties. Endeavour and Energex also requested clarification on the definition of these variables.[46]

Since we are not assessing the DNSPs' contractual arrangements and because the current opex categories will provide us with sufficient driver analysis information, we have removed the requirement to provide this information in the economic benchmarking RIN. Contractual costs will be considered under our other assessment techniques. For these reasons we have removed the requirement to separately report contactor costs that are part of opex.

Some NSPs noted the term "opex consistency" was unclear and Endeavour and Energex noted they did not provide some of the services.[47] We have amended the worksheet to provide additional clarity.

Endeavour Energy noted information for metering types 1–4 was excluded from metering opex and would need to be accounted for. As discussed above, to provided extra clarity we have amended the opex metering definition to only include metering types 5–7.

Energex requested clarification on whether actual opex for high voltage customers should also be included.[48] We have amended the definition to include both estimate and actual opex and a requirement to explain whether the input is an actual or estimated figure.

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[46] Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 5; Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

[47] Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 5; Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

4 Assets (RAB) Worksheet

4.1 RAB Allocation

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 capital inputs, which are overhead lines, underground cables and transformers and other capital.

The price 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 and 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 price of capital is derived using the value of capital (again the AUCC), and the quantity of capital measured by a physical proxy of capital (eg 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.

4.1.1 AER Position

The RAB categories are necessary in order to measure capital input costs for each asset category when undertaking economic benchmarking.

The draft RIN has been amended to remove the term 'sub-transmission'. The categories have been amended to only include distribution assets 66 kV or above. Categories referring to 'Sub-transmission substations and transformers' have been changed to 'zone substations and transformers'.

The variable 'Closing value for overhead asset value" has been renamed 'Closing value for overhead transmission asset value'.

The variable 'Underground distribution (cables)' has been amended to make clear that it is relevant to 'underground' assets.

We have also defined meters for the purposes of this category to provide that "Metering assets are asset used to provide metering services where metering services are Type 5-7 metering services as defined in the National Electricity Rules."

Instructions have been included to provide guidance in relation to providing data for the Assets (RAB) spreadsheet.

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[48] Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

4.1.2 Reasons for position

Collection of Data and General Measurement Issues

Values in the RAB are to be provided on an 'as incurred' basis by the NSPs, as opposed to an 'as commissioned' basis. Endeavour Energy and Energex noted this issue.[49] We understand that this issue may apply to assets where there is a time-lag between incurring the cost of investing in an asset, and commissioning the asset when it commences operations. However, this issue applies consistently between NSPs and in our view, is unlikely to affect a comparison of performance between NSPs.

Some NSPs submitted that they cannot directly attribute historical RAB asset values to the categories listed.[50] Some NSPs were concerned about the reliability and general quality of historical RAB data.[51] Energex submitted that RAB data is not available before 2006 for all categories except Asset Lives, which may not be available at all.[52] Data in relation to underground distribution assets may not be available for 2012. Ergon Energy submitted that the network assets as presented in the RAB, may be combinations of equipment types that may span several asset classes. Some NSPs, including Ergon Energy, submit that comparability may be a significant issue.[53]

Instructions have been included to provide guidance in relation to providing data for the Assets (RAB) spreadsheet. Where possible, historical RAB asset data is to be reported in accordance with actual historical RAB roll forward calculations. These calculations are to be undertaken on the following basis: Initial RAB values (RAB values at the time of the establishment of the RAB) are to be allocated to asset categories in accordance with information available on initial RAB assets and best estimates. This valuation is to then be rolled forward in accordance with actual historical RAB roll forward calculations. Inflation addition, regulatory depreciation, actual additions (recognised in RAB) and disposals are to be calculated in accordance with actual RAB values and parameters. Disaggregated RAB data must reconcile to totals. Where additional assumptions are required, these may be drawn from information in asset registers and/or statutory accounts as required.

TransGrid requested clarification on whether the "RAB Roll forward to end of period" reflects annual roll forward calculations or the roll forward between regulatory control periods.[54] We consider "end of period" in this context to refer to the end of the regulatory year rather than the regulatory control period . Any step changes in the RAB between regulatory periods should be included in the relevant year. For clarity, we have removed the term 'to the end of the period' from the heading.

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49 Endeavour Energy, *Endeavour Energy Submission to the AER on Draft Annual RIN to Apply 2012/13 to 2013/14*, p. 14. Energex, *Response to RAB allocation questions*, 6 August 2013.

50 Essential Energy, *Response to RAB allocation questions*, 17 September 2013. Jemena Electricity Networks, *Response to RAB allocation questions*, 2 August 2013; Jemena Electricity Networks, *Response to revised draft economic benchmarking templates*, 20 August 2013. SP AusNet, *Response to RAB allocation questions*, 2 August 2013. Some NSPs, such as TransGrid and Powerlink, submit this can be done to a reasonable level of accuracy after apportioning some asset classes. Grid Australia, *Response to RAB allocation questions*, 2 August 2013.

51 Submissions that raise these issues include: Networks NSW, *Response to AER regarding benchmarking data*, 13 September 2013; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Essential Energy, *Response to RAB allocation questions*, 17 September 2013; Jemena Electricity Networks, *Response to revised draft economic benchmarking templates*, 20 August 2013; Endeavour Energy, Endeavour Energy Submission to the AER on Draft Annual RIN to Apply 2012/13 to 2013/14; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013; Aurora Energy, *Response to revised draft economic benchmarking templates*, 20 August 2013; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013.

52 Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

53 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

54 Transgrid, Preliminary draft economic benchmarking templates, 27 August 2013, p. 1.

Ergon Energy requested clarification in relation to nature of the recorded expenditure in this sheet.[55] Where relevant, expenditure is inclusive of both system and non-system capex and overheads. In relation to 'DRAB0103 – distribution substations including transformers' and 'DRAB0107 – easements', we do not think it is necessary to further define these categories, however we will consider any proposed amendments to these definitions from Ergon Energy or any other stakeholder.

RAB Allocation and the application to Standard Control and Alternative Control Services

As discussed in the 'Scope of service definition' section, some NSPs submit they may have difficulties in separating historical RAB data into standard control services and other services components. Some NSPs submit that there is an assumption within the information request that the same RAB asset categories apply to both standard and alternative control services, and that the definitions are unclear. Ergon submitted that the relationship between information in the standard control services and other services components of the spreadsheet needs to be made clearer.[56]

As discussed above, we have amended the definition for 'network services' to clarify how network services interact with standard control services. Where NSPs are unable to provide exact figures, we are requesting that NSPs estimate the data and outline the estimation approach.

Sub-transmission assets

Some categories included 'overhead sub-transmission assets' and 'underground sub-transmission assets'. However, some NSPs argued that 'sub-transmission' is not a term used in the National Electricity Rules and therefore is potentially subject to various interpretations. Endeavour Energy submitted that the term sub-transmission would include feeders that are used to distribute electricity to zone substations from transmission connection points or sub-transmission substations, as well as feeders that distribute electricity from transmission connection points to sub-transmission substations.[57]

To avoid ambiguity in relation to the term 'sub-transmission', we have removed the term and renamed the categories 'Distribution assets 66kV and above. Categories referring to 'Sub-transmission substations and transformers' have been changed to 'zone substations and transformers'.

Capital contributions

Energex submitted that in Queensland, capital contributions are currently included in the RAB.[58] We note that capital contributions are included in the RAB for Queensland DNSPs whereas for other NSPs they are excluded. It is our intention to use the RAB data for the purposes of calculating the price of capital for NSPs. This will be used to weight a NSP's inputs when calculating its productivity. We do not consider that the inclusion or exclusion of capital contributions in the RAB will greatly affect this weighting.

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55 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Ergon Energy, *Response to RAB allocation questions*, 5 August 2013.

56 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013, p. 2. Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

57 Endeavour Energy, *Endeavour Energy Submission to the AER on Draft Annual RIN to Apply 2012/13 to 2013/14*, p. 9. Ergon Energy Corp Ltd, Submission to AER on RAB allocation question, 21 August 2013.

58 Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

However, we consider that it would be appropriate for the Queensland DNSPs to exclude capital contributions from their reported RABs for economic benchmarking, as we understand this is consistent with the approach taken by all other NEM NSPs. Further, excluding capital contributions from the RAB assets would ensure that the data is consistent across jurisdictions. We do not consider that it would be an overly onerous burden on Queensland DNSPs to report RAB data net of capital contributions. We have clarified the templates to require DNSPs to report RAB values net of capital contributions.

Asset lives and estimated residual service life

The information request in relation to RAB assets includes the category 'asset lives – estimated residual service life'. This is required in order to estimate the time that an existing asset can provide capital services to an NSP and assists in applying the appropriate calculations for depreciation purposes.

ElectraNet submitted that it is unable to estimate residual service life for asset categories including: overhead transmission assets, underground transmission assets, switchyard, substation and transformer assets, other assets with long lives and other assets with short lives. ElectraNet further submitted that in relation to the weights of 'asset lives – estimated residual service life', the variable can be weighted based on kilometres or head count. In relation to these categories, the weighting basis should be by contribution to asset value for each category. RAB is the preferred asset value measure for weighting.

If further disaggregation of the RAB within each category is not available, we suggest that replacement cost can be used as a reasonable proxy. Further, a reasonable proxy for replacement cost weights would be to weight by contribution to each category's capacity (ie MVA-kms for lines and for cables and MVA for transformers) although the weighting for the 'Other assets' category has to be by value. Where relevant, NSPs should provide a reasonable estimate for this data based on a 'best endeavours' basis and identify the basis of estimating the data in its response.

Citipower, Powercor and SA Power Networks submitted that, in relation to 'Estimate Service Life of New Assets' (DRAB13-01 – 09), the life of many assets would be unchanged for all reported time periods.[59] We note that this is likely to be the case for many reported RAB assets. That is, the expected total life of a category of new assets is likely to remain unchanged from one year to the next. An asset may have an expected total life of 10 years, regardless if it was bought in 2009 or 2010. This may be different if there is a sudden and substantial change in technology that increases the expected life of new assets in that category.

Easements and substation land

The information request in relation to RAB data disaggregates easements from other assets. This is in order to assess the materiality of easements as a cost driver for NSPs. Energex and Ergon requests further clarification on the category in which the land must be reported.[60]

Easements are to be recorded in the category labelled easements. Substation land should be recorded in the substation category.

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59 Citipower, Powercor and SA Power Networks, *Submission to AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 6.

60 Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013; Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

5 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.[61]

We are requesting data on the quantities and capacities of physical assets. Capacities are measured in MVA.

5.1.1 AER Position

The category '132kV sub-transmission assets' has been renamed to '132kV assets'.

The previous categories that referred to 33kV/44kV assets have been clarified to only refer to 33kV assets with a view that 44kV assets are to be included in 'Other overhead voltages' and DPA0209 'Other underground voltages'.

The definition of MVA ratings has been amended to the following:

> Indicate estimated typical or weighted average capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal or by voltage drop etc as relevant. – Give summer and winter rating if differentiated.

We have removed the heading 'Sub-transmission capacity variables' from the physical assets spreadsheet of the DNSP RIN.

The definitions of the variables in relation to 'length' have been amended so that they are based on 'segment length' without taking into account vertical components such as sag.

The templates have been amended to collect interconnector capacity together with the other capacity variables consistently with their definitions.

5.1.2 Reasons for position

Circuit Capacity MVA

The physical asset data include categories that are disaggregated into 'Estimated overhead network weighted average MVA capacity by voltage class' and 'Estimated underground network weighted average MVA capacity by voltage class'. Some NSPs have expressed concern about these measures. In particular, CitiPower, Powercor and SA Power Networks submit that they need additional information in relation to how far down the feeder the measurement should go. Other NSPs submit that this data is not normally measured and would need to be calculated. Ergon submitted that ratings may differ along distribution feeders and that the extremities of a distribution feeder may have many kilometres of much lesser rating.

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[61] The one-hoss shay assumption, or 'light bulb' assumption can be applied to assets that are generally subject to little physical deterioration over their lifetime and continue to supply a relatively steady stream of annual services over their lifetime, provided they are properly maintained. That is, they produce roughly the same service for each year of their life up to the end of their specified life.

Endeavour Energy submitted that weighted average line capacity is problematic and for 11/22kV, assumptions need to be made that may affect the accuracy of the estimates. Some NSPs submitted that the data may not be provided on a consistent basis because of concerns that include voltage drop and that the categories are not normally measured for situations where customers have recently paid for extra reliability.[62]

The data is required in order to aggregate the quantity of overhead lines and of underground cables into a total overhead lines quantity and a total underground cables quantity. The MVA conversion factors provide a way of doing this aggregation so that a common unit is assumed (effectively units of 'carrying capacity') to develop a MVA km input term for total factor productivity analysis. It should be noted that this MVA conversion factor is not related to the MW and MVA power factor used to estimate a MVA measure of maximum demand required in our operational data worksheet.

In relation to this data, we request a high-level weighted average MVA factor based on engineering knowledge within each business, as opposed to a detailed calculation for every line in the NSP's network. We observe that many Australian NSPs have been included in earlier economic benchmarking studies which used these conversion factors.[63] In these cases, the studies applied engineering estimates of the factors.

The definition has been amended to the following:

> Indicate estimated typical or weighted average capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal or by voltage drop etc as relevant. – Give summer and winter rating if differentiated.

Collection of Data

Some NSPs submit that they cannot provide all physical asset information for the time period requested. Some NSPs were concerned about the reliability and general quality of historical physical asset data. For example, ElectraNet submitted that information in relation to some installed transmission system transformer capacities can only be provided going forward, but it will not be able to provide historic data for this measure.[64] Some NSPs submitted that the data may be inconsistent between NSPs due to differences in service classification across jurisdictions and between the treatment of transmission and distribution services.

We note that some NSPs have submitted that they may not be able to provide all of the information in relation to physical assets that are requested in the templates.[65] Where they are unable to provide exact figures, we are requesting that NSPs estimate the data and outline the estimation approach.

We consider that it is appropriate to request a broad range of data for economic benchmarking, some of which not all NSPs will be able to provide. Some of the data may explain differences in relative productivity. Further, much of the data will be of interest to other stakeholders undertaking their own benchmarking analysis. By requesting and publishing this data, stakeholders will be able to conduct sensitivity analysis of economic benchmarking results using the data and develop their own models.

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62 Networks NSW, *Response to AER regarding benchmarking data*, 13 September 2013,p. 3.

63 For example, D Lawrence (2005), *Benchmarking Western Power's Electricity Distribution Operations and Maintenance and Capital Expenditure*, Report by Meyrick and Associates for Western Power Corporation, Canberra, 3 February.

64 Electranet, Excel workbook, *TNSP economic benchmarking data template Electranet comments*, 20 August 2013. Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

65 Jemena Electricity Networks, *Response to revised draft economic benchmarking templates*, 20 August 2013; Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013; Citipower, Powercor and SA Power Networks, *Submission to AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 4.

Publishing more data will give stakeholders more ability to conduct their own analysis and will ensure that a broader and longer series of data will be available for analysis.

132kV sub-transmission assets

As discussed, in order to undertake economic benchmarking, NSPs' physical asset data is needed that is disaggregated into a number of categories, including overhead sub-transmission 132 kV assets. Some NSPs submit that their former 132kV sub-transmission assets now perform a transmission function.

The category has been renamed to include all 132kV assets so that these assets are included in the RIN, whether they undertake a sub-transmission or a transmission function.

Clarification of 44/33 kV categories

Ergon submitted that the number “44” should be removed from the title of categories ‘Overhead sub-transmission 44/33 kV (if used as sub-transmission)’ and ‘Underground sub-transmission 44/33 kV (if used as sub-transmission)’. We understand that some NSPs do not have assets that are 44kV.[66]

The categories have been relabelled and, as noted above, amended to remove reference to subtransmission. These categories now only refer to 33kV assets. 44kV assets that would otherwise be included in this category are now to be included in the category ‘Other Overhead voltages’ or ‘Other Underground voltages’.

Data that is not applicable to some NSPs

Some NSP’s do not operate with cold spare capacity. In the case of CitiPower, Powercor Australia and SA Power Networks, this information is only available for spare zone substation transformers.[67] NSPs should identify this in their response to the information request. Further, some NSPs have submitted that they do not operate public lighting assets. NSPs should identify this in their response to the RIN.

Transformer capacity by summing single annual maximum demand for each customer

ElectraNet submitted that the definition of the category ‘Transformer capacity by summing single annual maximum demand for each customer’ is unclear.[68]

In this category, we seek information in relation to transformer capacities of directly-connected customers where the transformers are owned by the customer. Where the TNSP knows what the directly-connected customer's transformer capacity is it should include that information. Where this information is not available to the TNSP, we request a summation of non-coincident individual maximum demands of each such directly connected customer whenever they occur (that is, the summation of a single annual maximum demand for each customer) as a proxy for capacity within the customer's installation. Thus, 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. This was mistakenly included as two variables instead of one in the previous preliminary template. This has been corrected in the draft RIN.

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66 Ergon Energy Corp Ltd, *EECL Response to AER*, 21 August 2013, p. 4.

67 Citipower, Powercor and SA Power Networks, *Submission to AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 4.

68 Electranet, Excel workbook, *TNSP economic benchmarking data template Electranet comments*, 20 August 2013. Energex, Excel workbook, *Expenditure guidelines – DNSP economic benchmarking data template – Energex*, 26 August 2013.

Interconnector capacity

AEMO submitted a proposed amendment to the definition of interconnector capacity. We have made this amendment.[69] Further, to clarify the information requirements, we request interconnector capacity together with the other capacity variables.

[69] AEMO, *Response to AER draft expenditure forecast assessment guidelines for electricity transmission and distribution economic benchmarking templates*, 29 August 2013, p.2.

6 Operational data – distribution

6.1 Energy delivered by subcategories

As mentioned above, we are collecting information in the templates to calculate a billed output specification in addition to a functional output specification. The grouping of energy deliveries by chargeable quantity is required to apply a billed outputs specification. For this, information in relation to on-peak, shoulder and off-peak periods does not need to be consistent across NSPs. Rather, a NSP's actual on-peak, shoulder and off-peak periods can be applied. Likewise, we note these time periods may not necessarily reflect a NSP's actual peak and off-peak load times. More information on the use of a billed outputs specification is available in Economic Insights' report.[70]

6.1.1 AER position

In light of the clarification above, we have not made any significant changes to the energy grouping by chargeable quantity.

We have amended the variable 'Energy – received from TNSP by time of receipt' to include energy received from other DNSPs in light of submissions.

6.1.2 Reasons for position

DNSP submissions generally noted that their on-peak, shoulder and off-peak delivery times are different to those of other NSPs.[71] Jemena submitted it was unable to split energy into the proposed groupings.[72]

One NSP noted that it is only possible to provide this information with limiting assumptions. Further, some NSPs noted that the feeder classification used to define customers as urban and rural might not be appropriate. They noted that a rural feeder, under the AER's definition, might service customers that would be normally considered urban customers.

As mentioned above, if data is not available, the businesses should use best endeavours to provide an estimate of the data. For feeders where there are multiple types of customers, the customers should be classified based on the feeder classification. This will ensure consistency across NSPs.

CitiPower, Powercor and SA Power Networks submitted that the time periods will represent energy delivered at tariff peaks and the associated revenue. It will not accurately represent energy delivered or revenue received at system peak times, particularly where there are controlled loads.

As mentioned above, this data will be used for a billed outputs specification so tariff peaks are the appropriate measure.

CitiPower, Powercor and SA Power Networks noted only net energy delivered/received is available for embedded generation and solar photovoltaic installations as it is sourced from revenue metering. However the network must be built to accommodate gross energy receipt and delivery to cater for

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70 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 7.

71 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013; Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 5.

72 Jemena Electricity Networks, *Response to revised draft economic benchmarking templates*, 20 August 2013.

times when embedded generators and photovoltaic are not generating.[73] Another NSP noted that energy received from embedded generation is measured by accumulation in a billing period rather than at the time of receipt.

Since we are using this data for a billed outputs specification, we consider the embedded generation sourced from revenue metering to be sufficient in these circumstances.

Essential Energy considered '5.1 Energy delivery' variables to be targeted at some sort of loss calculation and that energy received from TNSPs by time of receipt would require a large amount of data.[74]

We consider '5.1 Energy delivery' variables to be a measure of energy throughput commonly used for billed outputs specifications. These variables are not intended to be used as a loss measure and that line losses are collected as a part of our quality of services variables. We recognise that collecting energy delivery variables may be onerous. However, we think that the collection of the data is justified for the purposes of undertaking sensitivity analysis.

6.2 Customer numbers

We are requesting DNSPs report customer numbers broken down in two ways, by location (ie. CBD, Urban, Rural) and by customer class (residential or non-residential for example). The collection of customer numbers by type may be used to normalise for the costs of serving different classes of customers. Further, customer numbers by type are being collected because they can potentially be used as an alternative output specification.

6.2.1 AER position

We consider customer types by location on the network should be based on the AER's feeder type classifications.

We have adjusted the customer classes to residential customers, non-residential customers not on demand tariffs, non-residential low voltage demand tariff customers and non-residential high voltage demand tariff customers.

6.2.2 Reasons for position

Customer types by location

Endeavour submitted that it did not have information relating to distribution numbers by location in its network and would assume that 100 per cent of customers fall into the "urban" classification.[75]

Some NSPs submitted that while certain feeders are classified as rural, all include urban customers along part of their length. Further, some NSPs do not have historical data on customers by feeder type.

We consider if the data has not been recorded then NSPs should provide an estimate of it using their best endeavours. For example, Aurora submitted that it records its customer numbers inconsistently

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73 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 7.

74 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 7.

75 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 6.

with the AER's requirements, but would allocate in accordance with a set of assumptions supported by documentation.[76]

Customer types by customer class

Jemena Electricity Networks noted that it had commercial customers on demand tariffs, who are not industrial customers. These customers include universities, supermarkets, shopping centres and libraries. The previously requested breakdown of customers could misrepresent the customer mix and how that mix drives costs, if this data were to be used for benchmarking.[77]

We consider the customer types should represent the DNSP's own customer mix. We have changed the categories to non-residential low voltage demand tariff customers and non-residential high voltage demand tariff customers rather than the previous industrial customer descriptors. The new customer classes better group customers in accordance with their technical characteristics such as connection voltage and whether they are on demand tariffs. This addresses Jemena's comment.

6.3 System demand

Maximum demand reflects the capacity that a NSP has been required to provide in the past. Workshop participants noted maximum demand could measure the load a NSP must be able to accommodate. Further we consider maximum demand may be appropriate in an alternative specification of a NSP's outputs. However we noted that maximum demand can be volatile which can affect the measurement of efficiency from one year to another. This could potentially be mitigated with the development of a less volatile measure of smoothed maximum demand.

6.3.1 AER position

In response to submissions we have made some amendments to the variables in '5.3 System demand'. We recognise the collection of maximum demand may be burdensome for some businesses. As outlined in the draft EFA explanatory statement we consider in the long term a smoothed measure of maximum demand should be adopted.[78] To develop this measure a long time series of data is required. This justifies the collection of historical data on maximum demand.

Definition of maximum demand

We have not changed the definition of maximum demand. However, our current definition of maximum demand calculated at the zone substation level does not take into account customers connected to the distribution network between the zone substation level and the terminal station level. We consider both measures of maximum demand to provide useful information for measuring outputs so we have amended the template to include maximum demand at both the zone substation and terminal station level.

Power factor conversion between MVA and MW DOPSD09

In response to submissions we have amended the definition to be:

> Power factor to allow for conversion between MVA and MW measures If both MVA and MW throughput for a network is available then the power factor is the total MW divided by the

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76 Aurora Energy, *Response to revised draft economic benchmarking templates*, 20 August 2013.

77 Jemena Electricity Networks, *Response to revised draft economic benchmarking templates*, 20 August 2013.

78 AER, *Explanatory statement - draft expenditure forecast assessment guidelines for electricity transmissions and distribution*, 9 August 2013, p. 103.

total MVA. If either the MW or MVA measure is unavailable then the NSP must provide an estimate of the average conversion factor.

Weather adjusted annual system maximum demand

Weather adjusted maximum demand is an output variable that can be used as an alternative to system capacity. We have amended the weather adjusted maximum demand variables to include both 10 per cent and 50 per cent probability of exceedance levels.

NSPs are to use best practice weather adjustment calculations as outlined by ACIL Allen.[79] The nature of these calculations should be explained in the data sources worksheet. For businesses that do not adjust for historical demands, an estimate should be provided based on its weather adjusted forecast demand methodology.

Demand supplied – and revenue from maximum demand charges

We are collecting contracted maximum demand and measured maximum demand for the billed outputs specification. These charges mainly apply to large industrial customers. These customers are charged on the basis of the actual observed maximum demand and the MW or MVA of reserved capacity for those industrial customers that are subject to reservation charges.

Where a DNSP does not distinguish or cannot disaggregate between contracted and measured maximum demand charges and revenue, this should be allocated to contracted maximum demand charges and noted in the data sources worksheet.

Where a DNSP does not charge on this basis, the yellow input cells can be greyed out.

6.3.2 Reasons for position

There were a number of submissions on the requested maximum demand data:

- Some NSPs submitted that they could not provide historical MW data or MVA data without estimation.
- ENA, CitiPower, Powercor and SA Power Networks submitted that maximum demand measures are requested at the zone substation level but this will fail to take account demand from customers directly connected at sub–transmission voltages. Maximum demand should therefore be measured at the terminal station level.[80]
- CitiPower, Powercor and SA Power Networks also submitted that coincident maximum demand is available but it is not used for planning purposes and does not reflect how the network is built to accommodate maximum demand.[81]
- Ergon Energy noted it successfully negotiated for the removal from its Annual Performance RIN of a requirement for Annual system maximum demand characteristics to be reported (in terms of

[79] ACIL Allen Consulting, *Connection point forecasting – A nationally consistent methodology for forecasting maximum electricity demand*, 26 June 2013, p. 19.

[80] CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 6; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 2.

[81] CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 6.

MVA) at the system level. This was because NSPs might not be able to provide the requested data.[82]

We consider the purpose of obtaining a maximum demand measure is to proxy required system capacity. A measure of maximum demand at the zone substation level better reflects required system capacity than a measure of maximum demand at the terminal station level. Maximum demand at the terminal station level is a higher level of aggregation that is less likely to reflect customers' peak energy usage in aggregate. However, the maximum demands of high voltage customers are also important.

We note the maximum demand measure at the zone substation level is consistent with our utilisation measure for system capacity and has been adopted in previous economic benchmarking studies.

We note that coincident system maximum demand is not used for planning purposes which is why we also collect data on non-coincident system maximum demand. However, coincident system maximum demand can provide a snap shot of a NSP's maximum demand and can be used as an alternative to non-coincident system maximum demand as a part of sensitivity analysis.

Annual system maximum demand

One NSP noted it did not make weather adjustments. Some submissions requested clarification on what probability of exceedance level should be adopted for the weather adjusted maximum demand figures.[83] As discussed above we have amended the template to include both 10 per cent and 50 per cent probability of exceedance levels for the weather adjusted maximum demands.

Ergon Energy also considered the benchmark data request does not account for reconciliation of system data with substation data by way of 'trimming'.[84] We are not comparing substation data with system data; rather we require NSPs to provide summated zone station maximum demand data as a measure of system wide maximum demand.

Ergon Energy also noted that obtaining this data may be data intensive and requires a new methodology that will not have been reviewed by external and independent consultancies.[85]

We recognise the development of estimation methodologies may be resource intensive and time consuming. However we consider that maximum demand (with and without weather adjustment) is a key output measure for economic benchmarking. If a NSP did not weather adjust in the past then unadjusted maximum demand can be provided. For guidance on an appropriate weather adjustment methodology, a detailed treatment is outlined by ACIL Allen.[86]

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82 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

83 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013; Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 2; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 6.

84 Ergon Energy Corp Ltd, *Email submission to Economic Benchmarking RIN*, 21 August 2013.

85 Ergon Energy, *Response to revised draft economic benchmarking templates*, 26 August 2013.

86 ACIL Allen Consulting, *Connection point forecasting – A nationally consistent methodology for forecasting maximum electricity demand*, 26 June 2013, p. 19.

Power factor conversion between MVA and MW

Submissions requested clarity on the purpose of a MVA and MW power factor conversion.[87] One NSP also noted that power factor conversion is known at the point of supply rather than at the substation level. This data is required for businesses that do not measure maximum demand in both MW and MVA terms. To allow cross NSP comparison we request these measures. This variable is required to compare NSPs that can provide either a MVA or MW figure for maximum demand but not both. We recognise that power factor conversion may vary across network areas and for this reason we are seeking, from each NSP, an average for their whole network. To provide more transparency in the calculations we have amended the worksheet to require NSPs to provide the average conversion factor for each voltage level. We note the average conversion factor for each voltage will have less variation across NSPs than the overall weighted average measure.

Demand supplied

Endeavour Energy requested clarification on the definition of demand supplied and to provide an example.[88] Other NSPs also noted the definition for summated chargeable maximum demand is difficult to interpret. As discussed above, we have amended the definition for this variable.

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87 Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 2; CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 6.

88 Networks NSW, *Response to economic benchmarking regulatory information notice consultation*, 16 September 2013, p. 5.

7 Operational data – transmission

We have clarified the operational data variables in light of the issues raised in submissions.

7.1.1 AER position

We consider energy delivered to other connected transmission networks should include both imported and exported energy and amended the definition.

We have amended the connection point variables to reflect the 'main grid' rather "highest transmission voltage".

We have included a power factor conversion variable. This variable is consistent with the power factor conversion variable discussed in the distribution operational data section.

7.1.2 Reasons for position

Transgrid requested clarity on whether energy delivered to other connected transmission networks should reflect the sum of both imported and exported energy.[89]

Transgrid also noted that for some TNSPs the "main grid" includes several transmission voltages and there may be few connection points at the highest transmission voltage (for example TransGrid's highest voltage is 500kV, but the majority of the main grid is 330kV).[90] We consider the connection point numbers variable should reflect the network in general. By changing the variable to reflect the main grid voltage rather than the highest voltage this should provide a more accurate picture of a TNSP's connection point numbers.

ElectraNet submitted that it did not have MVA capacity for annual system maximum demand and could assume a power factor but no audit assurance would apply.[91] Consistent with our position for DNSPs we consider the addition of a power factor conversion variable at all voltage levels to be appropriate.

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89 Transgrid *Response to revised draft economic benchmarking templates*, 27 August 2013.
90 Transgrid *Response to revised draft economic benchmarking templates*, 27 August 2013.
91 Electranet, Excel workbook, *TNSP economic benchmarking data template Electranet comments*, 20 August 2013.

8 Quality of service issues – distribution

8.1 Definitions of SAIDI and SAIFI

SAIDI is the system average interruption duration index and SAIFI is the system average interruption frequency index. Our distribution Service Target Performance Incentive Scheme (STPIS) defines SAIDI and SAIFI. These measures reflect the reliability of a distribution network and should be taken into account when measuring the quality of distribution services.

8.1.1 AER position

We have amended the templates to request SAIDI and SAIFI both inclusive and exclusive of major event days (MEDs).

The definitions around SAIDI and SAIFI have been clarified to outline the outages that are to be included and excluded in the measures.

The unit of measurement for SAIDI and SAIFI have been incorrectly stated. They should be minutes per customer and interruptions per customer respectively. The templates have been amended to reflect this.

8.1.2 Reasons for position

Treatment of MEDs

Citipower, Powercor and SA Power Networks note that severe weather events can drive marked volatility in annual reliability performance for a DNSP, and thus it is important to use adjusted reliability performance outcomes which remove the effects of certain severe weather events.[92] We agree that severe weather events can affect annual reliability performance. Consequently we have requested SAIDI and SAIFI data both inclusive and exclusive of MEDs.

To account for the effect of the variability of weather on the efficiency of electricity networks we also intend to develop a number of weather operating environmental factors. These will be based upon data available from the Bureau of Meteorology and will be developed in consultation with NSPs.

Clarification of the definitions of SAIDI and SAIFI

The definitions of SAIDI and SAIFI have been clarified defining unplanned outages and distribution outages. This will give NSPs clearer guidance on how to complete the templates. These definitions are consistent with the definitions in the distribution STPIS.

Units of measurement for SAIDI and SAIFI

SAIDI and SAIFI are most commonly measured as the average minutes off supply and interruptions per customer respectively. The units of measurements have been changed to reflect this.

8.2 Energy not supplied

Energy not supplied reflects the energy that was not delivered due to an outage on an electricity network.

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92 Citipower, Powercor and SA Power Networks, *Submission to AER on the revised draft data list for economic benchmarking*, 16 August 2013, p.6.

8.2.1 AER position

We have amended the definitions of energy not supplied to exclude outages that are outside the control of the NSP. We have also clarified the distinction between planned and unplanned outages. We also clarify that we request raw, unadjusted energy not supplied.

8.2.2 Reasons for position

Clarification of the definitions will give NSPs greater certainty as to what is required to be reported in the templates. These definitions are consistent with the STPIS.

Citipower, Powercor and SA Power Networks requested clarification as to whether energy not supplied was intended to be raw or normalised.[93] The energy not supplied measure is intended to reflect the detriment to customers of an outage. Hence we request raw energy not supplied. "Normalization" of energy not supplied adjusts the energy not supplied measure to reflect normal operating circumstances. This adjustment would not reflect the detriment to customers of the specific outage and hence would not be appropriate given the intended use of the parameter.

8.3 Capacity utilisation

Capacity utilisation measures the extent to which the capacity of an electricity network is used in a given year.

8.3.1 AER position

We have amended the definition of capacity utilisation to reflect the utilisation of capacity at the zone substation level.

8.3.2 Reasons for position

Citipower, Powercor and SA Power Networks submitted that we should not include network length in system capacity for the purpose of calculating network utilisation as it mean that network utilisation would be more a function of network length than the use of the network.[94] We agree with this point and to address it have adjusted the definition of capacity utilisation to measure utilisation at the zone substation level.

8.4 Network element reliability information

AEMO proposed that the AER expand the data requirements in the templates to include plant outage data for network elements, particularly network circuits and transformers, at each of the voltage levels in the NEM.[95] This data is more detailed than would be useable for economic benchmarking. As such we have not included the disaggregated data in our economic benchmarking templates. We will consider the collection of this data for the purposes of reviewing specific cost elements as part of our category analysis workstream.

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93 CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 5.

94 Citipower, Powercor and SA Power Networks, p6.

95 AEMO, *Response to AER draft expenditure forecast assessment guidelines for electricity transmission and distribution economic benchmarking templates*, 29 August 2013, p.3.

8.5 System losses

AEMO proposed the AER alter the definition of system losses.[96] We have updated the definition in light of AEMO's comment.

[96] AEMO, *Response to AER draft expenditure forecast assessment guidelines for electricity transmission and distribution economic benchmarking templates*, 29 August 2013, p.2.

9 Quality of service issues – transmission

9.1 Quality of service parameters

We intend to collect information on the quality of service of transmission networks in accordance with parameters in our 2012 transmission STPIS, which was amended to achieve as consistent an approach across all TNSPs as possible. The new version was also designed, with significant industry collaboration, to reduce the burden of collecting data associated with the new consistent definitions.

9.1.1 Collection of data

ElectraNet submitted that the AER should note that definitions of transmission STPIS parameters differ across jurisdictions. ElectraNet also stated that it is unable to provide much of the service performance data requested. Grid Australia noted that NSPs and consumers both raised the issue of unsuitability of STPIS parameters for economic benchmarking in workshops earlier in the year.

We note that the definitions of the STPIS *Loss of supply event frequency* parameters threshold for large and small events differs across jurisdictions, however we consider that these definitions are close enough for comparing performance. The differences, to a certain extent, normalise for the effects of operating environment factors. Over time we may make these definitions consistent if deemed necessary.

We note that NSPs may not be able to provide all of the information requested in the templates. Where they are unable to provide exact figures we are requesting that NSPs estimate the data and outline the estimation approach.

We note that in workshops some consumers and networks questioned the suitability of some STPIS parameters for economic benchmarking analysis. However, there has been broad agreement from stakeholders that reliability should, if possible, be included as a TNSP output. We consider that the collection and publication of a broad range of STPIS parameters for the purposes of economic benchmarking is appropriate. This will allow stakeholders to conduct sensitivity analysis of economic benchmarking results and will provide information that will be of use to stakeholders in interpreting the results of economic benchmarking analysis.

9.1.2 Network element reliability information

As per AEMO's recommendation for distribution reliability, we will consider network element reliability information as part of our category analysis workstream.

9.1.3 System losses

Consistent with the treatment of DNSP system losses, we have updated the definition of system losses in light of AEMO's recommendation.[97]

[97] AEMO, *Response to AER draft expenditure forecast assessment guidelines for electricity transmission and distribution economic benchmarking templates*, 29 August 2013, p.2.

10 Operating environment factors

Operating environment factors are used in economic benchmarking to account for factors that may unduly affect the relative productivity of businesses. We are collecting diverse information on operating environmental factors. Some of this data (particularly weather data) on operating environment factors will not be sourced directly from NSPs.

10.1.1 AER position

Weather station data

To accurately map the differences in weather across businesses we have added an additional requirement for the businesses to provide the suburb and weather station number of all weather stations within their network service area. While we have not included actual weather data in the template, we will work with the businesses to determine appropriate definitions for weather variables.

Standard vehicle access

We have amended the definition of standard vehicle access to include fenced and gated paddocks. We consider the purpose of this variable is to measure difficult terrain that cannot be accessed by a standard vehicle, this could be due to rocky terrain where a land vehicle would not be able to access the site where maintenance works need to be undertaken. Impediments such as fencing and gates would not fall under this category because the terrain would be suitable for a standard vehicle to access.

We have also amended all operating environment factors to require the route line length rather than the proportion of the network. This should clarify on what basis the terrain related operating environment factors should be calculated.

Bushfire risk

We have added a bushfire risk variable to the environmental factors worksheet. We request NSPs to provide the route line length (km) in high risk bush fire areas as defined by the relevant jurisdictional fire authority.

We consider a completely uniform definition of what constitutes high bushfire risk across all NSPs may not be achievable. However, classification applied by fire authorities in each jurisdiction would allow for a sensible comparison of bushfire risk across DNSPs.

Vegetation encroachment

We consider the previous definition of vegetation encroachment could be interpreted in a number of different ways. Economic Insights noted DNSPs operating in forested and other heavily treed areas will typically need to spend more on vegetation management than NSPs operating in grass land and other non-treed areas.[98] We have amended the vegetation encroachment coverage to include three aspects as follows:

- "The number of spans requiring vegetation management on a one year cycle. This variable does not include spans that are the responsibility of third parties such as Councils." We have also created two additional variables for the number of spans on a two year cycle and the number of spans on a three year cycle.

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[98] Economic Insights, Economic benchmarking of electricity network service providers, 25 June 2013, p. 77.

- "The proportion of spans in tropical or subtropical areas", and
- "The route line length where a legislative requirement exists to undertake vegetation management to mitigate high bushfire risk."

Concentrated load distance

We consider 30 per cent is a reasonable starting point for concentrated load distance but we are interested in the TNSPs' views on the appropriate threshold and variable definition.

Other operating environment factors

We consider operating environment factors can be captured both qualitatively and quantitatively as a part of economic benchmarking. Where possible operating environment factors should be captured quantitatively, this requires clear definitions that are comparable across NSPs.

Grid Australia provided an additional submission on operating environment factors.[99] Where these factors can be measured quantitatively with a clear definition, such as the bushfire risk variable, we have incorporated this into our data requirements. Other factors such as system operating voltages, maximum demand and age profile are captured in other areas of our template. Some factors such as 'variations in cost drivers between jurisdictions' and 'implications of technical requirements and standards set out in the schedules to Chapter 5 of the NER' appear to need to be assessed qualitatively.

10.1.2 Reasons for position

Weather station data

Citipower, Powercor and SA Power Networks requested the AER to be specific on what data has been requested from the Bureau of Meteorology.[100] The AER has obtained maximum and minimum temperature data, solar, rainfall, average wind speed and wind gusts from the Bureau of Meteorology and we will be requesting NSPs to specify which weather stations are in their networks.

We are not planning to request the raw data from the businesses but will require the businesses to list the weather stations in their service area.

Grid Australia considered the use of degree heating and cooling days is reasonable but the temperature thresholds will vary by state. Grid Australia submitted that these thresholds could be determined in agreement with each TNSP, probably aligning with the relevant temperature compensation function applied in demand forecasting.[101]

We agree that temperature thresholds may vary across states. We are currently working on appropriate climate related measures and have not requested this data in the templates. We have collected raw data from the Bureau of Meteorology which can be adjusted to reflect different temperature thresholds. We are interested in NSPs' views on the appropriate temperature thresholds in each state.

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[100] CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 7.

[101] Grid Australia, *Grid Australia environmental factors and effects*, 28 August 2013.

Standard vehicle access

ENA, CitiPower, Powercor and SA Power Networks requested more clarity on how the standard vehicle access variable should be measured.[102] As discussed above we have amended the definition to address these concerns and change the variable from a proportion measure to a measure of the route line length.

Bushfire risk

CitiPower, Powercor and SA Power Networks submitted that bush fire risk is a significant cost driver and recommended that the AER collect data on the percentage of service area classified as high bush fire risk areas.[103] Grid Australia also noted bushfire risk should be taken into account.[104]

As discussed above we have added a bushfire risk variable to the environmental factors worksheet.

Vegetation encroachment

CitiPower, Powercor and SA Power Networks submitted that the vegetation encroachment variable should be the total number of spans where the DNSP has primary responsibility for cutting the spans. Further, this measure is independent of a DNSP's control and of a DNSPs' cutting cycle. It is more representative of the effort and costs a DNSP will incur.[105] It was also noted that the current definition could result in a DNSP assigning 100 per cent value in all years on the basis that the entire network requires vegetation management at all times.

We agree that the previous definition could be interpreted in the manner raised by CitiPower, Powercor and SA Power Networks. The vegetation encroachment variable seeks to measure 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 requirements are a requirement beyond a NSP's control and provides an additional cost over NSPs that do not have this requirement.

We are interested in the NSPs' views on how the three factors can be taken into account in the vegetation encroachment variable. In particular, we are interested in what data is available that can directly measure the three factors listed above. The measures we have proposed attempt to capture key aspects of the three factors listed above.

Concentrated load distance

Concentrated load distance is an environmental factor that has not previously been applied to economic benchmarking studies of electricity networks. Grid Australia submitted that the choice of the

[102] Energy Networks Association, *Response to regulatory information notice requests dated 31 July and 5 August*, 16 August 2013, p. 3. and CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 7.

[103] CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 7.

[104] Grid Australia, *Grid Australia environmental factors and effects*, 28 August 2013.

[105] CitiPower, Powercor Australia and SA Power Networks, *Submission to the AER on the revised draft data list for economic benchmarking*, 16 August 2013, p. 8.

30 per cent threshold is unclear, and while it appears reasonable the parameter may be best tested at different thresholds for sensitivity.[106]

The choice of 30 per cent is a starting point based on engineering judgement. We agree with Grid Australia that different thresholds could be tested. We consider 30 per cent is a reasonable starting point and we are interest in the TNSPs' views on the appropriate thresholds to be included in any sensitivity analysis.

106 Grid Australia, *Grid Australia environmental factors and effects*, 28 August 2013.

A Revised definitions

DNSP templates

Variable code	Variable name	New definition
	General definitions	
DDEF0101	Network services	Network services relate to services provided over the shared network used to service all network users connected to it. Such services may include the construction, maintenance, operation, planning and design of the shared network. Network services are delivered through the provision and operation of apparatus, equipment, plant and/or buildings (excluding connection assets) used to convey, and control the conveyance of, electricity to customers. Network services also include the provision of emergency response and administrative support for other network services. Network services are a subset of standard control services that excludes connection services, metering services, fee based and quoted services and public lighting services.
DDEF0105	Connection services	As defined in the AER's Connection charge guidelines for electricity retail customers, June 2012, a connection service—means either or both of the following: (a) a service relating to a new connection for premises; (b) a service relating to a connection alteration for premises.
DDEF0209	Measured Maximum Demand charges	Charges calculated based on measured maximum demands, whether reset on a monthly basis or ratcheted. These do not include contracted maximum demand charges.
DDEF0403	Regulatory year	Each consecutive period of 12 calendar months in a regulatory control period (under the NER) or equivalent regulatory period under a preceding regulatory framework. The first such 12 month period commences at the beginning of the regulatory control period (or equivalent regulatory period, as the case may be) and the final 12 month period ends at the end of the regulatory control period (or equivalent regulatory period, as the case may be).
DDEF0404	Regulatory control period	As defined in the NER.
	Customer types	
DDEF0301	Residential Customers	Residential customer means a customer who purchases energy principally for personal, household or domestic use at premises. Residential customers will typically pay a fixed charge and a charge based on energy consumption.
DDEF0302	Non-residential customers not on	All customers that are not residential customers and who do not pay demand-based tariffs. These customers will typically pay a fixed

	demand tariffs	charge and a charge based on energy consumption.
DDEF0303	Non-residential low voltage demand tariff Customers	Non-residential customers that pay a charge based on either their actual maximum demand or a contracted level of demand and who are connected at 240 or 415 volts. These customers may also pay a fixed charge and a charge based on energy consumption in addition to the demand charge.
DDEF0304	Non-residential high voltage demand tariff Customers	Non-residential customers that pay a charge based on either their actual maximum demand or a contracted level of demand and who are connected at higher than 415 volts. These customers may also pay a fixed charge and a charge based on energy consumption in addition to the demand charge.
	Asset categories	
DDEF0601	Overhead distribution assets (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. It does not include pole-mounted transformers and associated equipment.
DDEF0602	Underground distribution assets (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. It does not include underground transformers and associated equipment.
	Sub transmission change	The term sub transmission is no longer used.
DDEF0603	***Distribution substations including transformers***	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.
DDEF0604	CBD feeder	A feeder supplying predominantly commercial or high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
DDEF0605	Urban feeder	A feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km.
DDEF0606	Short rural feeder	A feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km.
DDEF0607	Long rural feeder	A feeder which is not a CBD or urban feeder with a total feeder route length greater than 200 km.
	Quality of supply	
DDEF0801	Energy not supplied	The estimate of energy not supplied to be based on average customer demand (multiplied by number of customers interrupted and the duration of the interruption). Average customer demand to be determined from (in order of preference): (a) average consumption of the customers interrupted based on their billing history; (b) feeder demand at the time of the interruption divided by the number of customers on the feeder; (c) average consumption of customers on the feeder based on their billing history; (d) average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on

		the feeder. This measure excludes: - planned outages - load shedding due to a generation shortfall - automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition - load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator - load interruptions caused by a failure of the shared transmission network - load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning - load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
DDEF0802	Unplanned interruption	An interruption due to an unplanned event.
DDEF0803	Unplanned event	An event that causes an interruption where the customer has not been given the required notice of the interruption or where the customer has not requested the outage.
DDEF0804	Interruption	An interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premises. The customer interruption starts when recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. Does not include subsequent interruptions caused by network switching during fault finding. An interruption ends when supply is again generally available to the customer.
	2. Revenue	
DREV0105	Revenue from Off–Peak Energy Delivery charges	This category includes revenue from controlled load tariffs.
DREV0106	Revenue from unmetered supplies	Revenue from energy delivered for uses which are “calculated” rather than “metered”. This may include revenue from delivery of annual energy for traffic controls, energy component of street lighting, phone or transport cubicles.
	3. Opex	
DOPEX0201	Opex for network services	All opex related to network services. Network services are defined in DDEF0101.
DOPEX0202	Opex for metering	All opex related to type 5-7 metering services as defined in the NER.
DOPEX0206	Opex for high voltage customers	An estimate of the opex costs that would be associated with end–user contributed assets that are operated and maintained by directly connected end–users (eg transformers) if the operation and maintenance were provided by the DNSP (please describe basis of

		estimation). If actual data is available also include this.
	4. Assets (RAB)	The regulatory asset base as referred to in S6.2.1 of the NER.
	4.1 Regulatory Asset Base Values	The regulatory asset base for a distribution system owned, controlled or operated by a DNSP is the value of those assets that are used by the DNSP to provide standard control services, but only to the extent that they are used to provide such services. Where possible historical RAB asset data is to be reported in accordance with actual historical RAB roll forward calculations. These calculations are to be undertaken on the following basis: Initial RAB values (RAB values at the time of the establishment of the RAB) are to be allocated to asset categories in accordance with information available on initial RAB assets and best estimates. This valuation is to then be rolled forward in accordance with actual historical RAB roll forward calculations. Inflation addition, regulatory depreciation, actual additions (recognised in RAB) and disposals are to be calculated in accordance with actual RAB values and parameters. Disaggregated RAB data must reconcile to totals. Where additional assumptions are required, these may be drawn from information in asset registers and/or statutory accounts as required. RAB data must be reported net of capital contributions.
DRAB0103	Distribution substations including transformers	This category of RAB assets includes overhead and underground distribution substations, ground mounted substations, pole mounted substations and underground substations.
DRAB0108	Meters	Metering assets that are assets used to provide metering services where metering services are Type 5-7 metering services as defined in the National Electricity Rules
	Sub-transmission assets	All categories that refer to the term 'sub-transmission' have been amended to 'assets 66kV and above'. Other assets are referred to as 'network assets less than 66kV'. Categories referring to Sub-transmission substations and transformers was changed to 'zone substations and transformers'
	4.2 Annual RAB Roll forward	Relabelled 4.2 to Annual RAB Roll forward
	Asset Lives	The estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. This may not align with the asset's financial or tax life. Weightings are to be calculated in order of preference: 1. On the basis of the asset's share of the RAB for the category and expected asset lives; 2. If 1 is not available, an acceptable proxy is on the basis of replacement costs and expected asset lives; 3. If 1 and 2 cannot be applied, in accordance with the asset's contribution to the category's capacity (ie MVA-kms for lines and for

cables and MVA for transformers).

The weighted average asset life of each category may be calculated in the following manner: If Category 1 contains 2 assets; Asset 1 has an expected life of 50 years and a value of $3 million; and Asset 2 has an expected life of 20 years and a value $2 million, then the weighted average asset life of assets in this category is 38 years: [(3/5) x 50] + [(2/5) x 20] = 38. That is, the weighted average asset life of each category is:

$$\left(\frac{cost\ \ of\ asset\ 1}{the\ sum\ of\ the\ cost\ of\ assets\ in\ category 1}\right) x\ (the\ expected\ life\ of\ asset\ 1)$$

$$+\left(\frac{cost\ \ of\ asset\ 2}{the\ sum\ of\ the\ \ cost\ of\ assets\ in\ category\ 1}\right) x\ (the\ expected\ life\ of\ asset\ 2)$$

RAB is the preferred asset value measure for weighting but replacement cost is an acceptable proxy if disaggregation of the RAB to the relevant level is not possible. (And capacity shares are then a further proxy to replacement cost shares).

	5. Operational data	
	Energy - received from TNSP and other DNSPs by time of receipt	Energy received into the DNSP's network as measured at supply points from the TNSP and other DNSPs.
	5.2 Customer numbers	Distribution Customers are defined as the number of National Meter Identifiers (NMIs). Each NMI is counted as a separate customer.
	5.3 System demand	Annual system maximum demand to be collected at both the zone substation level and terminal station level.
DOPSD02,03, 05,06,08,08,11,12	Weather Adjusted System Annual Maximum Demand 10%/50% POE	The probability of exceedance level now included in the definition of the variable.
DOPSD13–DOPSD20	Power factor conversion between MVA and MW	Power factor to allow for conversion between MVA and MW measures. If both MVA and MW throughput for a network is available then the power factor is the total MW divided by the total MVA. If either the MW or MVA measure is unavailable then the NSP must provide an estimate of the average conversion factor.
	Demand supplied	This input is only relevant for DNSPs that charge on this basis. Where a DNSP cannot distinguish between contracted and measured maximum demand, this should be allocated to contracted maximum demand.
	6. Physical assets	
	6.1 Network capacity variables	Network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. It includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also

		wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.
	Circuit length	Calculated as circuit length from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length should not take into account vertical components such as sag.
DPA0108	Other overhead voltages	Alternatively, "legacy voltages" eg 6.6 kV or 110kV may be captured into the nearest relevant voltage currently in use. 44kV lines to be included here. Specify voltages and lengths for all 'Other overhead voltages'
	Circuit Capacity MVA	Indicate estimated typical or weighted average capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal or by voltage drop etc as relevant. – Give summer and winter rating if differentiated.
	6.2 Transformer Capacity Variables	Transformer capacity involved in lowest level transformation to the utilisation voltage of the customer. Do not include intermediate transformation capacity here (eg 132 kV or 66 kV to 22 kV or 11 kV distribution level). Give summation of normal nameplate continuous capacity / rating (with forced cooling etc if relevant). This includes cold spare capacity but excludes voltage transformers and current transformers.
DPA0502	Distribution transformer capacity owned by High Voltage Customers	Transformation capacity from high voltage of DNSP to customer utilisation voltage owned by customers connected at high voltage. This might include eg 11 kV or 22 kV to eg 3.3 kV as well as to LV; Alternatively give summation of individual maximum demands of high voltage customers whenever they occur (ie the summation of single annual MD for each customer) as a proxy for delivery capacity within the high voltage customers (if the latter is not known by the DNSP).
DPA0503	Cold spare capacity included in DPA0501	The capacity of spare transformers owned by the DNSP but not currently connected to the network.
DPA0601	Total installed capacity for first level transformation	For example 132 kV to 66 kV or 33 kV where there will be a second level transformation before utilisation at a lower voltage.
DPA0602	Total installed capacity for second level transformation	Total installed capacity where a second level transformation before utilisation at a lower voltage is applied. For example 66 kV or 33 kV to 22 kV or 11 kV .
	7. Quality of services	
DQS0101	SAIDI (System Average Interruption Duration Index)	The sum of the duration of each unplanned sustained Customer interruption (in minutes) (without any removal of excluded events and MEDs) divided by the total number of Distribution Customers (as defined in section 5.2 Customer numbers). Unplanned SAIDI excludes momentary interruptions (one minute or less).
DQS0102	Distribution–related unplanned SAIDI (whole of network)	The sum of the duration of each unplanned sustained Customer interruption (in minutes) (without any removal of excluded events and MEDs) divided by the total number of Distribution Customers (as defined in section 5.2 Customer numbers).. Unplanned SAIDI excludes momentary interruptions (one minute or less). This measure excludes: - planned outages

		- load shedding due to a generation shortfall - automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition - load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator - load interruptions caused by a failure of the shared transmission network - load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning - load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
DQS0104	Distribution–related unplanned SAIFI (whole of network)	Unplanned Interruptions (SAIFI) (without any removal of excluded events and MEDs) - The total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers (as defined in section 5.2 Customer numbers).. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions. This excludes: - planned outages - load shedding due to a generation shortfall - automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition - load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator - load interruptions caused by a failure of the shared transmission network - load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning - load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
DQS04	Overall network utilisation	Ratio of sum of non-coincident maximum demand at the zone substation level divided by summation of zone substation thermal capacity.
	8. Operating environment factors	
DOEF0202	Vegetation management - one year cycle	The number of spans requiring vegetation management on a one year cycle. This variable does not include spans that are the responsibility of third parties such as Councils.
DOEF0203	Vegetation management - two year cycle	The number of spans requiring vegetation management on a two year cycle. This variable does not include spans that are the responsibility of third parties such as Councils.
DOEF0204	Vegetation management - three year cycle	The number of spans requiring vegetation management on a three year cycle. This variable does not include spans that are the responsibility of third parties such as Councils.
DOEF0205	Tropical or subtropical area	The proportion of spans in tropical or subtropical areas.
DOEF0206	Bushfire legislative requirement	The route line length where a legislative requirement exists to undertake vegetation management to mitigate high bushfire risk.

DOEF0207	Standard vehicle access	Distribution line route length that does not have standard vehicle access. Areas with standard vehicle access are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks).
DOEF0208	Bushfire risk	The route line length in high risk bush fire areas as defined by the relevant jurisdictional fire authority
DOEF04	Weather station no.	DNSP to input the weather station number, post code and suburb for all weather stations in the DNSP's service area. The weather station numbers are available at the Bureau of Meteorology.

TNSP Templates

Variable code	Variable name	New definition
	General definitions	
TGDEF0201	Regulatory year	Each consecutive period of 12 calendar months in a regulatory control period (under the NER) or equivalent regulatory period under a preceding regulatory framework. The first such 12 month period commences at the beginning of the regulatory control period (or equivalent regulatory period, as the case may be) and the final 12 month period ends at the end of the regulatory control period (or equivalent regulatory period, as the case may be).
TGDEF0202	Regulatory control period	As defined in the NER.
	3. Opex	
	3.1.1 Opex categories and cost allocations	TNSPs are to report historical categories in accordance with their most recent IDR. These categories are to align with the activities in these regulatory accounts (eg. field support or network operations opex, etc). TNSPs may add additional rows where relevant.
	3.1.2 Opex categories and cost allocations 20XX - 20XX	TNSPs are to report historical categories in accordance with their IDR for the relevant time period. These categories are to align with the activities in these regulatory accounts (ie. field support or network operations opex). TNSPs may add additional rows where relevant. Section 3.1.2 is only relevant if a TNSP has changed opex categories and cost allocation methodologies over time. Where a TNSP has changed more than once, the TNSP may add more sections as required.
	4. Assets (RAB)	
	4.1 Regulatory Asset Base Values	The regulatory asset base as referred to in S6A.2.1 of the NER. Where possible historical RAB asset data is to be reported in accordance with actual historical RAB roll forward calculations. These calculations are to be undertaken on the following basis: Initial RAB values (RAB values at the time of the establishment of the RAB) are to be allocated to asset categories in accordance with information available on initial RAB assets and best estimates. This valuation is to then be rolled forward in accordance with actual

		historical RAB roll forward calculations. Inflation addition, regulatory depreciation, actual additions (recognised in RAB) and disposals are to be calculated in accordance with actual RAB values and parameters. Disaggregated RAB data must reconcile to totals. Where additional assumptions are required, these may be drawn from information in asset registers and/or statutory accounts as required. RAB data must be reported net of capital contributions.
TRAB0101	Overhead transmission assets (wires and towers/poles etc)	Assets used to conduct electricity from one point to another above ground. These include poles, towers, insulators, pole-top structures and overhead conductors. It does not include overhead conductors used for communication, signal or protection purposes, or for the reticulation or control of any street lighting system. Overhead substations and their associated connection , fuses and transformers, etc are to be separately regarded as assets classified as substations and/or transformers.
TRAB0102	Underground transmission assets (cables, ducts etc)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints, cable terminations and other assets used to connect the underground network to the overhead system (which, but for the cable connection, would not have been necessary). It does not include communication, signal or protection cables, or cables which form part of any street lighting system. Ground mounted, indoor or submerged substations and their associated enclosures, switchgear, transformers, etc are to be separately regarded as assets classified as substations and/or transformers.
TRAB0103	Substations, switchyards, Transformers etc with transmission function	Asset value of installations involved in transformation level indicated below. Include value of energised transformers and cold spare capacity. Include capacity of tertiary windings etc as relevant. Include relevant small equipment (eg circuit breakers and current transformers). Do not include step-up transformers at generation connection location. Asset value of installations at intermediate locations for transmission service function. This incorporates transmission switchyards, substations etc (eg 500 kV to 330 kV and 330 kV to 132 kV), including transformers and including switchyards without transformers. Include TNSP assets for connection to DNSPs or direct connected end use customers.
TRAB0107	Other assets with long lives (please specify)	Where used for provision of Prescribed Transmission services only. For asset lives 10 years or greater. Where relevant, includes secondary substation equipment (protection, telecommunication and control systems) where these assets have lives of 10 years or greater.
	4.2 Annual RAB Roll forward	Relabelled 4.2 to Annual RAB Roll forward
	Asset Lives	The estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. This may not align with the asset's financial or tax life. Weightings are to be calculated in order of preference: 1. On the basis of the asset's share of the RAB for the category and expected asset lives; 2. If 1 is not available, an acceptable proxy is on the basis of replacement costs and expected asset lives;

		3. If 1 and 2 cannot be applied, in accordance with the asset's contribution to the category's capacity (ie MVA-kms for lines and for cables and MVA for transformers). The weighted average asset life of each category may be calculated in the following manner: If Category 1 contains 2 assets; Asset 1 has an expected life of 50 years and a value of $3 million; and Asset 2 has an expected life of 20 years and a value $2 million, then the weighted average asset life of assets in this category is 38 years: [(3/5) x 50] + [(2/5) x 20] = 38. That is, the weighted average asset life of each category is: $\left(\frac{cost\ of\ asset\ 1}{the\ sum\ of\ the\ cost\ of\ assets\ in\ category 1}\right) x\ (the\ expected\ life\ of\ asset\ 1)$ $+\left(\frac{cost\ of\ asset\ 2}{the\ sum\ of\ the\ cost\ of\ assets\ in\ category\ 1}\right) x\ (the\ expected\ life\ of\ asset\ 2)$ RAB is the preferred asset value measure for weighting but replacement cost is an acceptable proxy if disaggregation of the RAB to the relevant level is not possible. (And capacity shares are then a further proxy to replacement cost shares).
	5. Operational data	
	5.1 Energy delivery	The amount of electricity transported through the TNSP's network in the relevant regulatory year (measured in GWh). Metered at the downstream settlement location rather than the import location to the TNSP.
TOPED0101	To Other connected transmission networks	This is to include both imported and exported energy.
	5.2 Connection point numbers	Now refers to main grid voltage rather than highest voltage.
	Power factor conversion between MVA and MW	Power factor to allow for conversion between MVA and MW measures If both MVA and MW throughput for a network is available then the power factor is the total MVA divided by the total MW. If either the MW or MVA measure is unavailable then the NSP must provide an estimate of the average conversion factor.
	6. Physical assets	
	Network length of circuit at each voltage	Calculated as circuit length (measured in kilometres) of lines in service (the total length of lines including interconnectors, backbone and spurs). A double circuit line counts as twice the length. Length does not take into account vertical components such as sag.
	Estimated network weighted average MVA capacity by voltage class	Indicate estimated typical or weighted average capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal or by voltage drop etc as relevant. – Give summer and winter rating if differentiated.
TPA0308	Other transmission voltages	Please specify voltages and capacities separately. Alternatively, “legacy voltages” or “alternative voltages” eg 110 kV may be captured

		into the nearest relevant voltage currently in use.
TPA0504	Transformer capacity for directly connected end-users owned by the end-user	Transformer capacity at connection point to directly connected end user where the capacity is owned by the directly connected end user. Where this information is not known to the TNSP it should be approximated by the summation of non-coincident individual maximum demands (in MVA) of relevant directly connected end users whenever they occur (ie the summation of a single annual MD for each customer) as a proxy for capacity within those end users' installations.