



Better Regulation

Explanatory statement

Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution

August 2013

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Shortened forms

Shortened term	Full title
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation (capital) expenditure
capex	Capital expenditure
CESS	capital expenditure sharing scheme
CPI	Consumer price index
CRG	Consumer Reference Group
DEA	Data envelopment analysis
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
EBSS	efficiency benefit sharing scheme
ENA	Energy Networks Association
ERA	Economic Regulation Authority of Western Australia
EURCC	Energy Users Rule Change Committee
F&A	Framework and Approach
MEU	Major Energy Users
MTFP	Multilateral total factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSP	Network service provider
Ofgem	Office of Gas and Electricity Markets
opex	Operating expenditure
PC	Productivity Commission
PIAC	Public Interest Advocacy Centre

PTRM	Post-tax revenue model
RAB	Regulatory asset base
repex	replacement (capital) expenditure
SFA	Stochastic frontier analysis
STPIS	Service target performance incentive scheme
TNSP	Transmission network service provider

Request for submissions

This explanatory statement is part of the Australian Energy Regulator's (AER) Better Regulation program of work, which follows from changes to the National Electricity and Gas Rules announced in November 2012 by the Australian Energy Market Commission (AEMC). The AER's approach to regulation under the new framework will be set out in a series of guidelines to be published by the end of November 2013.¹

Interested parties are invited to make written submissions to the AER regarding this explanatory statement and Guidelines by close of business, 20 September 2013.

At the same time as we are seeking submissions on this explanatory statement and Guidelines, we are also consulting on our category analysis and economic benchmarking data requirements. In particular, we have already commenced the process of seeking comment from stakeholders on the data requirements for our economic benchmarking models, in anticipation of issuing a draft regulatory information notice in September 2013. The timing for consultation on these data requirements is set out in section 1.5.

Submissions should be sent electronically to: [expenditure@aer.gov.au](mailto: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
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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 Further details on the consultation processes and other guidelines are available at <http://www.aer.gov.au/node/18824>.

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Executive Summary

The Australian Energy Regulator (AER) is Australia's independent national energy market regulator. Our role is to promote the national electricity and gas objectives. Enshrined in the Electricity and Gas Laws, these objectives focus us on promoting the long term interests of consumers.

A major part of our work is regulating the energy networks that transport energy to consumers (electricity poles and wires, and gas pipelines). In 2012, the Australian Energy Market Commission (AEMC) announced important changes to the electricity and gas rules, affecting our role in regulation. Our role is also changed by the energy market reforms that the Prime Minister announced on 7 December 2012.

We initiated the Better Regulation program to draw together these important reforms and our work in developing our regulatory processes and systems. The Better Regulation program involves us:

- extensively consulting on seven new guidelines that outline our approach to receiving and assessing network businesses' expenditure proposals and determining electricity network revenues and prices
- establishing a consumer reference group specially for our guideline development work, to help consumers engage across the broad spectrum of issues that we are considering
- forming an ongoing Consumer Challenge Panel (appointed 1 July 2013) to ensure our network regulatory determinations properly incorporate consumers' interests
- improving our internal technical expertise and systems, and our engagement and communication with all our stakeholders.

This explanatory statement accompanies the draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution networks (Guidelines). The National Electricity Rules (NER) require us to develop the Guidelines to specify:²

- the approach we will use to assess capital expenditure (capex) and operating expenditure (opex) forecasts, and
- the information we require from network service providers (NSPs) to do so.

The NER require NSPs to provide the information set out in the Guidelines with their regulatory proposals.³

National electricity and gas objectives

The objective of the National Electricity and Gas Laws is to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to—

- (a) price, quality, safety, reliability and security of supply of energy; and
- (b) the reliability, safety and security of the national energy systems.

² NER, clauses 6.4.5 and 6A.5.6; AEMC, *Rule determination*, 29 November 2012, p.114.

³ NER, clauses 6.8.2(c2) and 6A.10.1(h).

This explanatory statement explains our general assessment approach in more detail. This includes how we will assess total capex and opex proposals and implement new and refined techniques.

As part of the process of creating the Guidelines, we have taken the opportunity to review and improve our approach to assessing expenditure. In doing so, we have developed new assessment techniques and refined some of our existing techniques.

In particular, the Guidelines provide for a nationally consistent reporting framework that will allow us to benchmark expenditure at the category level. This means we can compare drivers of expenditure and the accompanying costs of conducting similar activities by each NSP across the National Electricity Market (NEM).

Further, the Guidelines set out data requirements for new economic benchmarking techniques such as multilateral total factor productivity, data envelopment analysis and econometric modelling. Economic benchmarking techniques will allow us to analyse the efficiency of NSPs over time and compared to their peers. They will also allow us to estimate a top down forecast of expenditure and estimate productivity change.

In addition to new techniques, we have taken the opportunity to refine and improve existing techniques to ensure the capex and opex allowances we approve are efficient. For example, we have implemented a new annual 'rate of change' approach to account for efficient changes in opex over time. This approach incorporates analysis of, and adjustments for, productivity. We have also developed a new augmentation capex (augex) tool to complement our existing replacement capex (repx) tool.

We will integrate our new and refined techniques into our assessment approach, but they will not displace our existing techniques. Rather, we will use them in combination with existing techniques to form a view about forecast expenditure. In particular, our preference is to continue to rely on revealed (past actual) costs as the starting point for estimating forecasts when we are satisfied they are efficient. However, if we find a material and unjustified difference between revealed costs and our assessment of efficient costs, we will depart from revealed costs in favour of benchmark costs.

Therefore, the Guidelines specify a standardised approach to data analysis using various techniques, but with a greater focus on benchmarking. We intend this standardisation to clarify our assessment approach for stakeholders, which will in turn significantly improve our decisions on efficient forecast expenditure allowances. The Guidelines reflect the need for flexibility in applying various techniques, recognising the specific issues faced by each NSP and potential implementation issues, such as collecting and testing new data and techniques.

To facilitate the techniques specified in the Guidelines, we will require much more information than in the past. We will release templates indicating our proposed data requirements in several stages. We will issue:

- preliminary expenditure information templates (attached to the draft Guidelines in August 2013).
- draft regulatory information notices (RINs) in September 2013 to all NSPs to collect back cast economic benchmarking data to enable a testing and validation process in early 2014
- RINs in late 2013 to all NSPs for the purposes of gathering information for the 2014 benchmarking report and in assessing regulatory proposals submitted in 2014.

We consulted on and carefully considered the additional cost and burden of this new information (which is ultimately borne by consumers) and balanced this against the significant expected improvements in the robustness of our assessments. In particular, regularly reporting on the relative efficiency of NSPs will assist network users in engaging more effectively in the process of setting efficient expenditure allowances in transmission and distribution determinations. The public scrutiny of NSPs' performance is likely to encourage them to keep improving, and to identify areas the AER is likely to target at the time of their next price review.

In finalising and implementing our Guidelines we will be mindful of consumer interests as referenced in the national electricity objective (NEO) and in the revenue and pricing principles, but also as preferences are expressed directly through our new means of consumer engagement. In particular, we will take a long-term perspective, recognising consumer interests in terms of price impacts as well as on service delivery and network security arising from potential under- or over-investment.

We consulted extensively with stakeholders in preparing the Guidelines, including an issues paper in December 2012 and subsequent workshops on various elements of our proposed approach. We will consult further on the Guidelines in the coming months, particularly given the long lead time in finalising detailed data requirements in time for our next round of resets and our first annual benchmarking report in 2014.

1 Introduction

The AER is responsible for the economic regulation of electricity transmission and distribution services in eastern and southern Australia under chapters 6 and 6A of the NER. We also monitor the wholesale electricity market and are responsible for compliance with and enforcement of the NER. We have similar roles for gas distribution and transmission under the National Gas Rules (NGR).

This explanatory statement is the next phase of stakeholder consultation on the Guidelines for electricity NSPs. It forms part of our Better Regulation program of work following from the AEMC's changes to the NER and NGR made on 29 November 2012. These reforms aim to deliver an improved regulatory framework focused on the long-term interests of energy consumers.

The improved regulatory framework provides us with additional strength and flexibility in setting revenues and prices for NSPs.⁴ One of the changes is a requirement for us to develop Guidelines for electricity transmission and distribution.⁵

1.1 Purpose of the Guidelines

The requirement for us to develop Guidelines arose after the AEMC amended the NER to address our concerns with expenditure assessment. We were concerned that restrictions in the NER resulted in inefficient NSP capex and opex allowances.⁶ Specifically, we were concerned the language in the NER implied that the AER must determine expenditure allowances using the approach taken by the NSP in its proposal.⁷

The AEMC's rule amendments clarify the approach the AER may take to assess expenditure, and removes ambiguities—particularly regarding our ability to use benchmarking.⁸ They require the AER to publish an annual benchmarking report, which we must consider when we assess expenditure proposals.⁹ The amendments also facilitate early engagement between NSPs and the AER on NSP expenditure forecasting techniques. This is so the AER and NSPs are aware, in advance, of the information the AER requires to appropriately assess a NSP's proposal.¹⁰ The Guidelines form part of this engagement process, which will potentially save time and effort for the AER and NSPs later in the process.¹¹

1.2 Stakeholder engagement

An intended outcome of the AEMC's rule changes was to facilitate more timely and meaningful engagement between the AER, consumer representatives and NSPs.¹² In informing the Guidelines, we engaged extensively with NSP and consumer representatives. We published an issues paper, invited written submissions from stakeholders and held 18 workshops on our proposed approach to assessing expenditure.¹³ We held additional bilateral meetings upon request. We also liaised regularly with consumer representatives through the AER's Consumer Reference Group (CRG). The CRG's verbal submissions and our responses are listed in a separate table in Attachment C.

⁴ AEMC, *Rule determination: Rule change: Economic regulation of network service providers, and price and revenue regulation of gas services*, 29 November 2012, pp. xx (AEMC, *Rule determination*, 29 November 2012, p. i).

⁵ AEMC, *Rule determination*, 29 November 2012, p.109.

⁶ AEMC, *Rule determination*, 29 November 2012, p. vii.

⁷ AER, *Directions paper submission*, 2 May 2012, p. 11 and Appendix 2.

⁸ AEMC, *Rule determination*, 29 November 2012, p. 92.

⁹ AEMC, *Rule determination*, 29 November 2012, pp.vii–viii.

¹⁰ AEMC, *Rule determination*, 29 November 2012, p. 114.

¹¹ AEMC, *Rule determination*, 29 November 2012, p. 110.

¹² AEMC, *Rule determination*, November 2012, p. 32.

¹³ Summaries of workshop discussions are available from our website: <http://www.aer.gov.au/node/19487>.

Importantly, we were able to test the application of new techniques and their detailed design with NSPs, reflecting upon their views of cost drivers and operating environments. Consumer representatives also provided valuable input to the process, and challenged positions put forward by NSP representatives. We consider the views of stakeholders in detail in this explanatory statement.

1.3 Overview of expenditure assessment in the context of the regulatory review process

The AER's assessment of a NSP's capex and opex forecasts is part of a multi-stage process that commences with a 'framework and approach' (F&A) stage and ends with a final determination.¹⁴ In the F&A stage, we must publish a paper that outlines our proposed approach to assessing a NSP's proposal. Our final determination sets out the NSP's revenue allowance for the forthcoming regulatory control period, which is typically five years in length. The Guidelines are a reference point throughout the regulatory review process.

1.3.1 The Guidelines

The Guidelines are not a stage in the typical review process, but a key input to it. The amendments to the NER require us to publish the Guidelines by 29 November 2013, and thereafter, they must be in force at all times.¹⁵ We do not need to develop Guidelines as part of every review.

The Guidelines must outline the types of assessments we will undertake in determining expenditure allowances and the information we require from NSPs to facilitate those assessments.¹⁶ The NER do not stipulate how detailed the Guidelines should be beyond these requirements. However, they provide some guidance to NSPs on how we are likely to assess their expenditure forecasts and the information we will require from NSPs to do so.¹⁷

The Guidelines are not binding on the AER or anyone else. However, if we make a determination that is not in accordance with the Guidelines, we must state in our reasons for determination why we departed from the Guidelines.¹⁸ NSPs are not required to explain departures from the Guidelines. However, they must provide with their regulatory proposals, a document complying with the Guidelines or—if we deviate from the Guidelines—the F&A paper.¹⁹ The NER allow us to require a NSP to resubmit its regulatory proposal if it does not comply with the Guidelines.²⁰ Therefore, we drafted the Guidelines so it balances flexibility and certainty.

1.3.2 Framework and approach stage

The NER require a NSP to advise us, during the F&A process, of its approach to forecasting expenditure.²¹ This allows us to consider the NSP's forecasting approach before we publish our F&A paper, which we must do 23 months before the NSP's existing determination expires. The F&A paper must advise the NSP of the specific information we require, and whether we will deviate from the

¹⁴ The NER uses the terms 'determination' and 'decision' for distribution and transmission, respectively. However, in this explanatory statement, when we use 'determination' we are referring to transmission as well as distribution.

¹⁵ NER, clauses 6.4.5(b), 6A.5.6(b), 11.53.4 and 11.54.4.

¹⁶ AEMC, *Rule determination*, 29 November 2012, p.114.

¹⁷ We provide specific information requirements in RINs.

¹⁸ NER, clauses 6.2.8(c) and 6A.2.3(c).

¹⁹ NER, clauses 6.8.2(c2) and 6A.10.1(h).

²⁰ NER, clauses 6.9.1 and 6A.11.1.

²¹ Clauses 6.8.1A and 6A.10.1B of the NER require the NSP to inform the AER of the methodology it proposes to use to prepare forecasts. It must do this at least 24 months prior to the expiry of the determination that applies to the NSP, or if there is none, then three months after the AER requires it to do so.

Guidelines.²² That is, it will clarify how the Guidelines will apply to the NSP under review. The F&A paper is not binding on the AER or the NSP, subject to some exceptions.²³

While the NER place no restrictions on NSPs' forecasting methods, some of the techniques and data requirements specified in the Guidelines and F&A paper (which NSPs must comply with) may draw NSPs away from methods they employed in the past. In particular, NSPs may find it useful to devote more effort to justifying their proposed opex allowances through the base-step-trend approach, where the AER has a strong preference to rely on revealed costs, if they have not used it in the past. This is explained in section 4.2 and chapter 5.

1.3.3 Determination stage

The determination stage commences when the NSP submits its proposal—17 months before its existing determination expires. At the same time, the NSP must submit accompanying information that complies with the Guidelines, or any deviations we specify in our F&A paper.²⁴

This information is not, and does not form part of, the NSP's expenditure forecast included in its proposal unless the NSP chooses to include the compliant information as part of its proposal.²⁵ However, if the NSP does not provide this information we may require the NSP to resubmit its regulatory proposal.²⁶

Box 1 First pass assessment

Recent changes to the NER require us to publish issues papers as part of the regulatory determination process and annual benchmarking reports.

Given these requirements a new element of the process is the 'first pass' assessment, which will indicate our preliminary view on the NSP's proposal.

This first pass assessment will typically involve high level expenditure assessment (using economic benchmarking and category analysis) and consideration of the NSP's performance in the most recent annual benchmarking report.

It will enable us to identify and engage with stakeholders on key issues early in the determination process.

When we assess the NSP's proposal we must publish an issues paper.²⁷ Following consultation with stakeholders, we then publish a draft determination. The NSP may submit a revised proposal in response to our draft determination, and then we will publish our final determination.

The purpose of the issues paper is to identify, reasonably early in the process, the key issues likely to be relevant in assessing the NSP's proposal.²⁸ We must hold a public forum and invite written submissions on the issues paper to encourage stakeholder engagement.²⁹ At this stage, we

²² NER, clauses 6.8.1, 6.8.2(c2), 6A.10.1A and 6A.10.1(h).

²³ NER, clauses 6.8.1(f) and 6A.10.1A(f).

²⁴ NER, clauses 6.8.2 and 6A.10.1.

²⁵ AEMC, *Final rule change determination*, 29 November 2012, p.114.

²⁶ NER, clauses 6.9.1 and 6A.11.1.

²⁷ In some cases the NER do not require an issues paper to be published, see for example 11.56.4(o), however we may still do so.

²⁸ We must publish an issues paper within 40 business days of determining that the NSP's proposal and accompanying information sufficiently complies with the NER and NEL. NER, clauses 6.9.3 and 6A.11.3.

²⁹ NER, clauses 6.9.3 and 6A.11.3.

are likely to conduct a 'first pass' assessment, which will indicate our preliminary view on the NSP's expenditure forecasts.

If applicable, we may know at the issues paper stage if the NSP's proposal requires us to depart from the assessment techniques outlined in our Guidelines.³⁰

The next step is for us to publish a draft determination, which includes the total capex and total opex forecasts we consider comply with the NER. We again facilitate stakeholder engagement by inviting written submissions on the draft determination and holding a predetermination conference.³¹ A NSP may submit a revised proposal in response to our draft determination. However, it may only do so to incorporate the substance of any changes we require or to address matters we raise in the draft determination.³² We may allow submissions on a revised proposal if we consider we require stakeholder input.³³

Following public consultation and submissions, the final step is for us to make and publish a final determination. We must do so no later than two months before the NSP's existing determination expires.³⁴ The final determination includes our conclusion on our assessment of expenditure forecasts and the estimate of total capex and total opex that we consider comply with the NER. This estimate may be different to the draft determination estimate, reflecting stakeholder submissions or other information.

This explanatory statement explains in further detail the expenditure assessment process that we apply throughout the regulatory review process, including the techniques we use to assess expenditure, and the information we require to do so.

1.3.4 Annual benchmarking reports

The NER now require us to publish annual benchmarking reports, beginning in September 2014.³⁵ The purpose of these reports is to describe, in reasonably plain language, the relative efficiency of each NSP in providing prescribed transmission services or direct control distribution services over a 12 month period.

Annual benchmarking reports are a key feature of the AEMC's recent rule change determination. It is intended that the reports would be a useful tool for stakeholders (including consumers) to engage in the regulatory process and to have better information about the relative performance of NSPs.³⁶

Benchmarking reports may arise at any time in the determination process for each NSP. The NER expenditure factors state that the AER must consider the most recent and published benchmarking report in making draft and final determinations. We must use our best endeavours to publish at a reasonable time prior to making a determination, any analysis on which we seek to rely, or to which we propose to refer, for the purposes of the determination.³⁷ The NER does not impose the same requirements at the draft decision stage.³⁸ However, the NEL requires that the AER must ensure

³⁰ AEMC, *Rule determination*, November 2012, p.114.

³¹ NER, clauses 6.10.2 and 6A.12.2.

³² NER, clauses 6.10.3 and 6A.12.3.

³³ NER, clauses 6.10.3(e), 6.10.4, 6A.12.3(g) and 6A.12.4.

³⁴ NER, clauses 6.11.1, 6.11.2, 6A.13.1 and 6A.13.2.

³⁵ NER, clauses 6A.31 and 6.27.

³⁶ AEMC, *Rule determination*, 29 November 2012, p.108.

³⁷ NER clauses 6.11.1(c) and 6A.13.1(a2).

³⁸ NER clauses 6.10.1 and 6A.12.1.

NSPs are informed of material issues under consideration and are given a reasonable opportunity to make submissions about a determination before it is made.³⁹

1.4 Summary of key topics

This explanatory statement focuses on how we developed the Guidelines, in light of extensive stakeholder consultation and industry guidance. In essence, we explain how we will assess expenditure, but with a particular focus on improvements to our approach. This explanatory statement addresses several key topics:

- **New assessment techniques**—We are expanding our regulatory toolkit to make greater use of benchmarking. In particular, we are implementing top down benchmarking techniques as recommended by the Productivity Commission (PC) and endorsed by the AEMC and the Australian Government.⁴⁰ We explain how we intend to apply these new techniques to assess expenditure forecasts.
- **Refined techniques**—We are refining some of our existing techniques to ensure the capex and opex allowances we approve are efficient. We explain our reasons for modifying the techniques, how this affects the way we assess expenditure and the interaction with incentive schemes.
- **Assessment principles**—We explain some best practice principles we may consider when forming a view on expenditure proposals. Our assessment techniques may complement each other in terms of the information they provide so we may need to consider the appropriateness of certain techniques as part of our holistic assessment approach. These principles are equally relevant to the techniques that we use to assess expenditure and techniques NSPs use to forecast expenditure.
- **Information requirements**—Part of improving our assessment approach is collecting consistent data from all NSPs. We explain what data we need and why, when we intend to collect it, and how we will collect it.

1.5 Next steps

Table 1.1 shows the next steps in the Guidelines' development. Full details of our expected consultation on data requirements and other implementation milestones are contained in chapter 6.

Table 1.1 Milestones for expenditure forecast assessment guidelines

Milestone	Due date
Issue draft Guidelines and indicative data templates	9 August 2013
Stakeholder workshops (if required)	September/October 2013
Submissions due on draft Guidelines	20 September 2013
Publish final Guidelines	29 November 2013

³⁹ NEL section 16.1(b)

⁴⁰ See, for example, *Productivity Commission, Electricity Network Regulatory Frameworks – Final Report*, Volume 1, 9 April 2013, pp. 27–32; AEMC, *Final rule change determination*, 29 November 2012, pp.vii–viii; Australian Government, *Response to the Productivity Commission Inquiry Report – Electricity Network Regulatory Frameworks*, June 2013, pp. i–ii.

While the Guidelines set out information we require to assess regulatory proposals, the indicative data templates cover only the information requirements for our assessment techniques that are changing significantly—category analysis and economic benchmarking. We are seeking feedback specifically on these information requirements as they are new and we consider they are necessary to improve our ability to assess expenditure.

We will consult with stakeholders over the coming months, with a view to issuing RINs in late 2013. As we consider our views on the data requirements for economic benchmarking are close to finalised, we intend to commence the formal process to collect that information in September 2013. We have already circulated the economic benchmarking data requirements to stakeholders and are seeking further views on these by 16 August 2013.

Reset RINs will remain our primary instrument to collect data and information for expenditure analysis. These RINs will cover the non-standardised information we require, and will be developed prior to determinations. The information requested in these RINs has not been set out in our indicative templates as they are not changing substantially (i.e. data requirements for base-step-trend opex analysis).

2 Draft Guidelines: context and content

This chapter provides the context for our work in developing the draft Guidelines. This context is important to understand our approach to consultation as well as the scope and content of the draft Guidelines.

This chapter summarises the broad purpose and objectives of the Guidelines and the improvements they introduce to the economic regulation of NSPs. It also discusses our approach to assessing capex and opex forecasts in previous determinations. This identifies the scope for improvements we seek to deliver using the new and standardised expenditure assessment techniques contained in the Guidelines.

2.1 Recent rule changes and requirements

The AEMC published changes to the NER on 29 November 2012.⁴¹ The rule changes enhance our capacity to determine the revenues of distribution and transmission businesses so consumers pay only efficient costs for reliable electricity supply.⁴² These were the result of rule change proposals the AER and a group of large energy users (the Energy Users Rule Change Committee) separately submitted in 2011.

The AEMC changed several key areas of the determination process, notably:

- rate of return
- capex incentives
- setting capex and opex forecasts
- the regulatory process.

We are conducting a program of work to put the AEMC's changes to the NER into effect. Developing the Guidelines is a major component of this work program.⁴³

The AEMC's changes clarified some existing provisions and created new requirements for the AER and NSPs regarding expenditure forecasts. In particular the AEMC:

- reaffirmed the NSP's proposal should be the starting point for analysis and we should accept the proposal if we are satisfied it meets the legal requirements. However, the AEMC removed the requirement for our decision to be based on the NSP's proposal if we did not approve the proposal, or an element of it. It also removed the restriction in the distribution rules that our decision only amend the NSP's proposal to the minimum extent necessary to enable it to comply with the NER.
- confirmed the NER do not place any restrictions on us to consider various analytical techniques. The AEMC highlighted administrative law may be sufficient in ensuring NSPs have a reasonable

⁴¹ The AEMC also published changes to the National Gas Rules. This draft explanatory statement concerns only the changes to the NER, which applies to electricity distribution and transmission businesses.

⁴² www.aemc.gov.au/electricity/rule-changes/completed/economic-regulation-of-network-service-providers-.html (accessed 22 May 2013).

⁴³ More information on the Better Regulation work program can be found on the AER's webpage: www.aer.gov.au/Better-regulation-reform-program

opportunity to respond to material we seek to rely upon. The addition of a new 'any other' capex/opex factor supports this.⁴⁴

- reaffirmed the role of benchmarking as a key factor in determining the efficiency of NSP expenditures. The NER now require us to publish benchmarking reports annually and made these reports part of a capex/opex factor.⁴⁵ The AEMC also removed the requirement to consider the circumstances of the particular NSP when determining the costs a prudent operator would incur to meet the capex/opex objectives.
- required us to publish the Guidelines. The F&A process will determine how the Guidelines apply to individual NSPs.
- required NSPs to inform us of their methods for forecasting expenditures 24 months before the next regulatory control period commences (this coincides with the F&A process).

The AEMC intended the Guidelines to facilitate early engagement on a NSP's expenditure forecast methodology. This will ensure both we and NSPs are aware, in advance, of the information we require to assess a NSP's proposal. The Guidelines will bring forward and potentially streamline the regulatory information notice stage(s) that currently occur, and will expedite our understanding of the NSP's approach to expenditure forecasting. The Guidelines do not restrict our ability to use additional assessment techniques if we consider these are appropriate after reviewing a NSP's proposal.⁴⁶

2.2 The AER's previous assessment approaches

Overall, we consider our first round of reviews reflected a transition to the national regulatory regime. The next section examines overall transitional and data collection issues, while sections 2.2.2 and 2.2.3 examine our approaches to assessing capex and opex in more detail.

2.2.1 Approach to data collection

Before transitioning to a national regulatory framework (which began in New South Wales and the ACT in 2008) state regulators were responsible for regulating DNSPs. These regulatory regimes imposed varying information requirements on DNSPs, and used different expenditure assessment approaches.

In our first round of distribution determinations, we recognised the transition to a national framework could potentially impose costs and create uncertainty for stakeholders. We also tended to adopt the previous regulatory regime's information requirements to enable time series comparisons.

While this enabled the transition to the national framework, it meant the opex and capex information collected differed for each jurisdiction. Inconsistent data requirements meant we could not rely on benchmarking analysis to any significant degree. This, in turn, hindered the development of more sophisticated benchmarking techniques and systematic assessment approaches across jurisdictions.

Expenditure information collected from DNSPs as well as TNSPs tended to be at the aggregate level, providing little opportunity to understand expenditure drivers beyond basic trend and ratio analysis. We typically had to request more detailed information, such as business cases, from NSPs. While such information was useful in deciding if particular projects or programs were efficient, we generally could not use this information for comparison or benchmarking because it was specific to the NSP.

⁴⁴ NER, clauses 6.5.6(e)(12), 6.5.7(e)(12), 6A.6.6(e)(14) and 6A.6.7(e)(14).

⁴⁵ NER, clauses 6.5.6(e)(4), 6.5.7(e)(4), 6A.6.6(e)(4) and 6A.6.7(e)(4).

⁴⁶ AEMC, *Rule determination*, 29 November 2012, p. 114.

This did not allow for meaningful insights on the efficiency of the NSP's overall expenditures, relative to other NSPs and over time. It also resulted in a dependency on expert engineering reviews to consider the efficiency of NSP proposals, at the expense of developing a meaningful and ongoing understanding of NSP performance in-house and also among key stakeholders.

2.2.2 Capital expenditure

In previous determinations, we used broadly similar approaches to assess the different categories in NSPs' capex forecasts. However, the details of the approach may have differed between determinations, and between businesses. These differences reflected various factors including the transition from state-based regulation to national regulation for DNSPs; differences between DNSPs and TNSPs; and the different circumstances surrounding each regulatory proposal.

The basic assessment elements were:

- assessment of the capital governance framework
- assessment of the capex forecasting method
- detailed review of a sample of projects and/or programs.

Capital governance framework assessment

We assessed the governance framework to see whether it reflected good industry practice. For example, we assessed whether the governance framework contained appropriate delegation and accountability. Assuming the governance framework reflected good industry practice, we then assessed whether the NSP followed the governance framework when developing its capex forecast.

Generally, we did not find the assessment of capital governance frameworks to be helpful in past determinations, especially considering their high cost. Given the general nature of capital governance frameworks, there was rarely a direct link between a NSP's capital governance framework and its capex forecast. We found that most capital governance frameworks were reasonable, but that did not adequately assure us that the NSP's capex forecast was reasonable. Our capex forecast assessment invariably relied much more on our assessment of the NSP's capex forecasting method and our detailed reviews (discussed below).

Expenditure forecasting method assessment

We assessed the methodology the NSP used to derive its capex forecast, including its assumptions, inputs and models. Similar to the capital governance framework review, we assessed whether the methodology would produce capex forecasts that reasonably reflect the NER criteria. NSPs had to justify any aspects of the model we considered did not appear reasonable. If the NSP could not justify its approach, we adjusted the methodology so it was a reasonable basis for developing capex forecasts that we considered reasonably reflected the NER criteria.

This is similar, for example, to our assessments of the probabilistic models that some TNSPs used to develop augmentation expenditure forecasts. We assessed the models and generally found them to be reasonable. However, in some cases, we did not consider the inputs to these models (such as

demand forecasts or certain economic scenarios) to be reasonable, so we adjusted those particular inputs.⁴⁷

We will continue to assess NSPs' capex forecasting methods in future determinations. As we discussed in section 2.1, however, the NER no longer constrain us to amend or substitute expenditure forecasts based on the NSP's proposal, which includes the capex forecasting method. This constraint was a problem in past determinations because many NSPs used 'bottom up builds' to derive their capex forecasts. Our assessments, therefore, relied largely on detailed reviews of projects and/or programs. In future reviews, we will use other types of analysis to inform our capex forecast assessments (see section 4.3).

Detailed reviews

We performed detailed reviews of a sample of projects and/or programs that comprised the NSP's capex forecast. For TNSPs, it usually entailed sample project reviews. For DNSPs, it usually entailed reviews of material programs given the large number of projects. The detailed reviews analysed business cases, cost estimations and other supporting documentation. Technical (and other) consultants typically assisted us with the detailed reviews. We assessed asset management plans and business cases the NSP used to justify expenditure, and whether these documents and processes would produce efficient expenditure forecasts. This entailed assessing whether:

- there was a genuine need for expenditure projects and/or programs
- the processes would identify efficient and viable options for meeting the need
- the processes would result in selection of the most efficient (lowest net present value (NPV)) option.

We also considered any 'step changes' that might have occurred that would explain why forecasts were not consistent with prior trends. For TNSPs, we also assessed whether particular projects could be better classified as contingent projects.

On the one hand, detailed project reviews provided useful analysis in past determinations, particularly for TNSPs who tend to propose a small number of high value projects. On the other hand, detailed reviews are intrusive and are not feasible when assessing DNSPs' capex forecasts given the (typically) large number of projects. We also relied on the judgement and industry experience of consultants for the detailed reviews, including for sample selection and for adjusting project or program costs. Hence, we could not always rely on the results of a sample to make inferences about the remaining projects and programs.

Our consultants also provided revised expenditure forecasts for projects they found to be inefficient in detailed reviews. Consultants typically have databases of the cost items that comprise NSP projects; the quality and currency of such databases vary, however, and they are usually not transparent. Hence, consultants tended to also rely on judgement and industry experience when proposing revised expenditure forecasts for projects.

While the NER do not require us to assess projects and programs, we are likely to continue to perform detailed reviews of some projects and/or programs in future determinations, particularly for TNSPs. Detailed reviews may still assist us in forming a view on whether a NSP's total forecast capex

⁴⁷ For example, see AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 107–117.

reasonably reflects the capex criteria because of the lumpy and often unique nature of certain capex activities. However, the Guidelines introduce assessment techniques and information requirements that will make our capex assessment approach more standardised, systematic and rigorous (see section 4.3).

2.2.3 Operating expenditure

We generally used the 'base-step-trend' approach as our primary tool to assess NSPs' opex proposals in past determinations. As with capex assessment (see section 2.2.2), the details of our approach may have differed between determinations, and between businesses. These differences reflected various factors including the transition from state-based regulation to national regulation, and the nature of each NSP's regulatory proposal.

When using the base-step-trend approach, we typically used actual opex in a base year (usually the fourth year of the previous regulatory control period) as the starting point for base opex if the NSP was subject to an efficiency benefit sharing scheme (EBSS). If there was no efficiency sharing mechanism in place, we assessed the components of a NSP's base opex in more detail, sometimes with the assistance of technical consultants. If necessary, we removed inefficiencies and non-recurrent costs from actual expenditure in the base year. We also used various forms of benchmarking, such as ratio and trend analysis, to inform our assessment of opex forecasts.

We then adjusted base year opex to account for changes in circumstances that will drive changes in opex in the forecast regulatory control period. These adjustments included:

- escalating forecast increases in the size of the network ('scale escalation')
- escalating forecast real cost changes for labour and materials ('real cost escalation')
- adjusting for efficient costs not reflected in the base opex, such as costs due to changes in regulatory obligations and the external operating environment beyond the NSP's control (step changes).⁴⁸

The base-step-trend approach is relatively established for determining opex forecasts in determinations, and we will continue to use it in future determinations. The Guidelines introduce assessment tools and information requirements that improve our application of the base-step-trend approach. Previous determinations made limited use of robust benchmarks, for example, so the relative efficiency of businesses and their productivity gains over time were not clear. Section 4.2 describes ways that attempt to clarify these issues.

2.3 The Guidelines—Better regulatory processes and outcomes

This section outlines how the Guidelines will implement the changes to the NER and improve the regulatory process for stakeholders at a broad level. Key changes include:

- national consistency (data requirements and assessment approach)
- more detailed information requirements
- greater transparency and consultation
- greater scope for benchmarking.

⁴⁸ AER, *Draft decision: Aurora Energy Pty Ltd 2012–13 to 2016–17*, November 2011, p. 158.

These changes attempt to address the limitations of our previous approach, as we discussed in section 2.2. Chapter 4 and Attachments A and B discuss how specific techniques and assessment methods in the Guidelines will improve expenditure forecast assessment.

2.3.1 National consistency

The Guidelines will set out a nationally consistent approach to assessing NSPs' opex and capex forecasts. They will also form the basis for developing nationally consistent information reporting templates for NSPs.⁴⁹ National consistency would contribute greatly towards expenditure forecast assessment approaches that are rigorous, transparent and cost effective.

Where possible, we aim to develop a suite of assessment approaches that optimises the regulatory process. A nationally consistent approach to expenditure forecasting assessment and data collection facilitates this in several ways. The Guidelines will facilitate greater synergies because stakeholders will be able to transfer experience from one determination to other determinations. All stakeholders will face greater certainty and transparency about our approach and thus engage more fully before, and during, the determination timeframe.

Nationally consistent data will also facilitate the development of more sophisticated benchmarking techniques and other expenditure forecast assessment techniques (see Attachments A and B).

2.3.2 More detailed information requirements

The Guidelines set out the key information we will require to undertake more rigorous expenditure forecast assessment in future determinations. We will collect capex and opex information that is more detailed and disaggregated than it was for previous determinations and annual reporting requirements. We can then use various assessment techniques such as the models for replacement expenditure (replex) and augmentation expenditure (augex) in future determinations (see Attachment B).

In addition to forecasts of future work volumes and costs required for regulatory proposals, NSPs will be required to comply with RINs and Regulatory Information Orders (RIO) that record the actual works undertaken, and the input costs associated with these works. Going forward, we intend to request data for network health indicators related to network reliability and condition using these instruments. As soon as possible, we will also collect back cast data to enable us to test, validate and implement our new economic benchmarking techniques.

We will also use data submitted as part of annual reporting for benchmarking reports and to assess expenditure forecasts. We propose the categories and subcategories of expenditure used for annual reporting should be the same as those used for expenditure forecasts. This is consistent with a number of stakeholder submissions that indicated the annual RIN process should be used to gather information for broader regulatory purposes.⁵⁰

Submissions often indicated we must consider the likely cost of complying with a RIN in determining data requirements and that the likely costs should not outweigh the benefits of extra data collection.⁵¹

⁴⁹ This is discussed in more detail in chapter 6.

⁵⁰ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p 18; Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 2.

⁵¹ CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 8; Ausgrid, Endeavour Energy and Essential Energy, *NSW DNSP submission on Forecast Expenditure Assessment Guideline -Issues Paper*, 14 March 2013, p. 5; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure*

We consulted on and considered likely costs and benefits of data collection in coming to a view on the data we propose to collect. Since we are collecting more information than—and in some cases, different information to—previous processes, stakeholders should read this draft explanatory statement and the Guidelines in conjunction with the draft information templates available on our website at <http://www.aer.gov.au/node/18864>.

2.3.3 Greater transparency and consultation

The Guidelines set out the techniques we will use as part of our expenditure forecast assessment approach (see Attachments A and B). NSPs and other stakeholders will thus have transparency about key areas of our assessment approach and decisions on efficient expenditure forecasts.

The Guidelines, with the F&A process, will facilitate consultation on NSPs' forecasting approaches well before the determination process. In past determinations, this debate typically occurred after the draft decision, when there was limited opportunity for change and to collect new data to assess expenditure claims. Stakeholders will continue to have input to developing our assessment methods as part of ongoing consultation on the Guidelines over 2013. We expect this process will work towards ensuring the assessment methods are robust and strike an appropriate balance between information burdens and improved regulatory outcomes.

NSPs will get an early indication of areas of their expenditure forecast we may target for further review, from the published techniques in the Guidelines, and from the data analysis we present in annual benchmarking reports. Ideally, the NSPs will address these potential concerns, appropriately justifying those areas in their regulatory proposals. This would increase the time we (and other stakeholders) can devote to analysing material issues and reduce the time spent gathering additional information.

The Guidelines also establish data reporting requirements that will support new annual benchmarking reports. Along with existing performance measures and data on work volumes, this will create an effective means of publicly monitoring NSP efficiency. We expect such monitoring and scrutiny to positively influence NSP behaviour and deliver value for money for network customers, as well as enabling consumer representatives to more effectively engage in regulatory processes.

2.3.4 Greater scope for benchmarking

The AEMC's changes to the NER allow us to use benchmarking more widely across the NEM. Specifically, the NER require us to publish an annual benchmarking report,⁵² which we must consider when assessing expenditure forecasts during a determination.⁵³ However, in the process of developing the Guidelines, we have also taken the opportunity to refine our assessment approach to make greater use of benchmarking techniques. The Guidelines are an efficient means to describe the information we will require to benchmark expenditure for determinations and annual benchmarking reports. However, the Guidelines do not prevent us from using other benchmarking techniques in the future.

Benchmarking is a valuable assessment technique in natural monopoly regulation. It provides us and other stakeholders with the information to compare NSPs with themselves and their peers, which may

Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A - Expenditure forecast assessment guideline, 15 March 2013, p. 2; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 3.

⁵² NER, clauses 6.27 and 6A.31.

⁵³ NER, clauses 6.5.6(e)(4) and 6.5.7(e)(4).

mitigate information asymmetry. Publication of benchmarking analysis may also act as a form of competitive pressure on NSPs.

Collecting better quality, nationally consistent data allows us to develop and use more sophisticated benchmarking techniques. Such benchmarking analysis provides a more rigorous approach to considering whether a NSP's expenditure forecast reflects efficient and prudent costs under the NER.⁵⁴ Attachments A and B describe the benchmarking techniques we will use in determinations and annual benchmarking reports.

⁵⁴ NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

3 Legislative requirements

This chapter outlines the requirements of the NEL and NER that govern the framework for assessing a NSP's expenditure proposal. Our Guidelines must be consistent with and give effect to these requirements. The following sections of this chapter:

- summarise the relevant provisions of the NEL and NER
- discuss expenditure assessment tasks under these provisions
- explain our view of the role of the Guidelines in this assessment framework.

3.1 National Electricity Law requirements

The NEL sets out the requirements that govern how we must perform our economic regulatory functions and powers, including assessing a NSP's proposal. These requirements include the NEO, the revenue and pricing principles and procedural fairness.

3.1.1 The national electricity objective and the revenue and pricing principles

The NEL requires us to perform our economic regulatory functions in a manner that will, or is likely to, contribute to achieving the NEO.⁵⁵ The NEO is:⁵⁶

... to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

- (a) price, quality, safety, reliability and security of supply of electricity; and
- (b) the reliability, safety and security of the national electricity system.

The NEO is the overarching objective of the NEL and exists to ensure we regulate electricity networks effectively. As the Major Energy Users (MEU)⁵⁷ and the PC⁵⁸ note, the second reading speech introducing the NEL explains the meaning of the NEO.⁵⁹

The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.

The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised.

The second reading speech clarifies that the NEO is fundamentally an efficiency objective where 'efficiency' is delivering electricity services to the level demanded by consumers in the long run at the lowest cost. Innovation and investment are necessary to ensure NSPs continue to respond to

⁵⁵ NEL, section 16(1)(a).

⁵⁶ NEL, section 7.

⁵⁷ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 4–7.

⁵⁸ Productivity Commission, *Final report: Electricity network regulatory frameworks*, June 2013, pp. 133–134.

⁵⁹ The NEO was initially called the national electricity market objective, which is why this quote refers to the 'market objective'. Second reading speech, National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005, Parliament of South Australia, Hansard of the House of Assembly, 9 February 2005, p. 1452. The purpose of the second reading speech is to explain the purpose, general principles and effect of the bill. See, for example, www.apf.gov.au/About_Parliament/House_of_Representatives/Powers_practice_and_procedure/00_-_Infosheets/Infosheet_7_-_Making_laws.

consumer needs and to improve productivity. However, to be efficient and maximise consumer welfare, service providers must innovate and invest at the lowest cost.

We agree with the MEU and the PC that the NEO seeks to emulate effectively competitive market outcomes.⁶⁰ In a competitive market, a firm has a continuous incentive to respond to consumer needs at the lowest cost (that is, operate efficiently) because competition may force it to exit the market if it does not. In addition, the firm has an incentive to improve its efficiency because it will enjoy greater market share if it can provide the best service at the lowest cost to the consumer. Essentially, the NEO imposes the pressures of competition on natural monopolies.

The revenue and pricing principles support the NEO (and the competitive market outcomes concept). They are guiding principles to ensure a framework for efficient network investment exists, irrespective of how the regulatory regime and the industry evolve (via changes to the NER).⁶¹ The relevant second reading speech explains that the revenue and pricing principles are:⁶²

...fundamental to ensuring that the Ministerial Council on Energy's intention of enhancing efficiency in the National Electricity Market is achieved.

The revenue and pricing principles reiterate the importance already enshrined in the NEO of ensuring NSPs have appropriate incentives to provide, and are compensated for providing, electricity services efficiently so that consumers receive the level of service they expect at the least cost.⁶³ They guide us to consider the regulatory and commercial risks involved in providing services, for example, in light of the economic implications for consumers of under- and over-investment in the network. They also guide us to consider the need to compensate NSPs for economically efficient investment so they have an incentive to maintain service levels, but not under- or over-utilise existing network assets.⁶⁴

The NEL requires us to take the revenue and pricing principles into account whenever we exercise discretion in making those parts of a distribution determination or transmission determination relating to direct control network services.⁶⁵ This includes when we assess expenditure forecasts. However, we may also account for the revenue and pricing principles when performing or exercising our other economic regulatory functions or powers if we consider it appropriate.⁶⁶ The principles are:

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—

- (a) providing direct control network services; and
- (b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

⁶⁰ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 4–7
Productivity Commission, *Final report: Electricity network regulatory frameworks*, June 2013, pp. 133–134.

⁶¹ Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

⁶² Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

⁶³ Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

⁶⁴ Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

⁶⁵ NEL, section 16(2)(a)(i).

⁶⁶ NEL, section 16(2)(b).

- (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
- (b) the efficient provision of electricity network services; and
- (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted [in a previous determination or in the Rules]

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

The regulatory framework under which we operate aims to facilitate the NEO and the revenue and pricing principles (and effectively competitive markets) in two ways. It requires us to:

- set NSP revenue allowances at the minimum cost required to provide the level of service consumers expect
- provide NSPs with incentives to pursue efficiency gains.

We reward NSPs in the short term for spending less in a regulatory control period than the forecast expenditure allowance that we determine to be efficient, while maintaining service standards. That is, our incentive framework encourages NSPs to continuously improve the efficiency with which they deliver electricity services without lowering service levels.

In theory, consumers benefit from this by paying the lowest cost for electricity services at the standard from which they gain the most value over the long term. In practice, this can be difficult to achieve because it relies on our ability to determine an efficient revenue allowance. This explanatory statement details the improvements we are making to our expenditure assessment approach to better achieve the NEO. We are also implementing a capex incentive scheme, which further encourages NSPs to pursue efficiencies.

3.1.2 Procedural fairness

The NEL also requires that we afford NSPs procedural fairness. We must, in making a regulatory determination, ensure NSPs are:⁶⁷

- (i) informed of material issues under consideration by the AER; and
- (ii) given a reasonable opportunity to make submissions in respect of that determination before it is made.

In essence, this protects a NSP if we materially change our analysis without notification.⁶⁸

⁶⁷ NEL, clause 16(1)(b).

⁶⁸ AEMC, *Rule determination*, 29 November 2012, p. 111.

3.2 National Electricity Rules requirements

The NER set out specific requirements to ensure we assess and determine expenditure proposals in accordance with the NEL, and hence give effect to the NEO. They prescribe the process we must follow when assessing expenditure.

3.2.1 Expenditure criteria

The NER require us to assess total capex and opex forecasts against the capex and opex criteria (collectively, the expenditure criteria). We must decide whether we are satisfied that a NSP's proposed total capex forecast and total opex forecast reasonably reflect the following criteria:⁶⁹

- (1) the efficient costs of achieving the capex and opex objectives
- (2) the costs that a prudent operator would require to achieve the capex and opex objectives
- (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capex and opex objectives.

These criteria intend to give effect to the NEO.⁷⁰ Accordingly, when we are determining whether a forecast reasonably reflects the expenditure criteria, we consider whether it reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the capex and opex objectives.

3.2.2 Expenditure objectives

The capex and opex objectives (collectively, the expenditure objectives) are to:⁷¹

- (1) meet or manage the expected demand for standard control/prescribed transmission services over that period
- (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control/prescribed transmission services
- (3) maintain the quality, reliability and security of supply of standard control/prescribed transmission services
- (4) maintain the reliability, safety and security of the system through the supply of standard control/prescribed transmission services.

Essentially, expected demand and the reliability, quality, security and safety standards (legislated or otherwise) are proxies for the level of service from which customers gain the most value. However, the shift towards a more consumer focused regulatory determination process will hopefully result in consumers having more input into ensuring service standards are at the level from which they gain the most value and hence are willing to pay for.⁷²

⁶⁹ NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

⁷⁰ AEMC, *Rule determination*, 29 November 2012, p. 113.

⁷¹ NER, clauses 6.5.6(a), 6.5.7(a), 6A.6.6 and 6A.6.7.

⁷² AEMC, *Rule determination*, 29 November 2012, pp. 114–5, and pp. 174–5; NER, clauses 6.5.6(e)(5A), 6.5.7(e)(5A), 6A.6.6(e)(5A) and 6A.6.7(e)(5A).

There is currently a concern that expenditure objectives (3) and (4) could result in customers paying more for services than they value.⁷³ The AEMC is considering a rule change proposed by the Standing Council on Energy and Resources (SCER) to address this issue by clarifying the expenditure objectives in the NER. The change would ensure NSPs are only able to include sufficient expenditure for quality, reliability and security in their regulatory proposals to comply with jurisdictional standards.⁷⁴

We have developed our draft Guidelines on the basis of the current rules, and we will review them if further AEMC rule changes require us to change our assessment approach. That said, these changes should not affect our Guidelines because the assessment techniques we employ to examine the efficiency of past and forecast expenditures include considering the NSPs' legal obligations in addition to the quality of service or outputs they propose to deliver.

3.2.3 Expenditure factors

In determining whether expenditure reasonably reflects the expenditure criteria, we must consider the capex and opex factors (collectively, the expenditure factors).⁷⁵ The expenditure factors are not additional criteria for assessing forecasts. Rather, they guide our assessment under the expenditure criteria; much like the revenue and pricing principles guide our decision-making.

Essentially, these factors ensure that we consider certain information in forming our view on the reasonableness of a forecast.⁷⁶ Some examples are benchmarks, consumer input, past expenditure, input prices and investment options. We may also consider 'any other factor' (if necessary) but we must notify the relevant NSP before it submits its revised proposal if we intend to do so. We could, but are not required to, also raise other factors at the F&A stage.⁷⁷

A key feature of the AEMC's recent rule change determination is that we must prepare annual benchmarking reports on the relative performance of NSPs. The AEMC intended the reports to be a useful tool for stakeholders, such as consumers, to engage in the regulatory process and to have better information about the relative performance of NSPs.⁷⁸ The expenditure factors require us to consider the most recent and published benchmarking report when assessing total capex and total opex proposals.

We will not necessarily have regard to every expenditure factor when assessing or determining every expenditure component; the NER do not require this.⁷⁹ Further, the NER do not prescribe weightings to the factors so we have discretion about how we may have regard to them, which we will explain in our reasons for a determination.

3.3 The AER's task

Taking into account the NEL and NER requirements, our task is to form a view on NSPs' expenditure forecasts in the context of the broader incentive based regulatory framework, where the overarching

⁷³ AEMC, Draft Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013, 27 June 2013, pp. i-iii.

⁷⁴ AEMC, Draft Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013, 27 June 2013, pp. i-iii.

⁷⁵ NER, clauses 6.5.6(c), 6.5.7(c) 6A.6.6(c) and 6A.6.7(c).

⁷⁶ AEMC, *Rule determination*, 29 November 2012, p. 113.

⁷⁷ AEMC, *Rule determination*, 29 November 2012, pp. 110–1.

⁷⁸ AEMC, *Rule determination*, 29 November 2012, p.108.

⁷⁹ AEMC, *Rule determination*, 29 November 2012, p. 115.

objective is to maximise the economic welfare of consumers over the long term.⁸⁰ That is, when we assess whether a NSP's expenditure forecast reasonably reflects the expenditure criteria, we are also considering whether the NSP is responding to incentives and therefore is providing electricity services efficiently.

If we are satisfied that a NSP's total capex or total opex forecast reasonably reflects the expenditure criteria, we must accept the forecast.⁸¹ If we are not satisfied, we must not accept the forecast.⁸² In this case, we must estimate the total forecast that we are satisfied reasonably reflects the expenditure criteria.⁸³ That is, we must amend the NSP's estimate, or substitute it with our own estimate. What is reasonable is a matter for us to determine, based on the information before us.⁸⁴

Two fundamental points are relevant to how we perform our task. First, the NER requires us to form a view on forecast total capex and opex, rather than subcomponents such as individual projects and programs. Second, we are not limited in the information we rely on to determine the reasonableness of a proposal and (if necessary) the appropriate substitute.

3.3.1 Total forecast assessment

The NER explicitly require us to form a view on total capex and total opex, not individual projects or programs.⁸⁵ In the past, we relied on project assessment in many cases to inform our opinion on total capex or opex. However, we are developing our assessment techniques and enhancing our approach so we can rely less on project assessment, particularly for DNSPs.

3.3.2 Information we can rely on

We are not limited in the information we can rely on to determine the reasonableness of a NSP's expenditure proposal. The information provided in the NSP's proposal is central to our assessment approach because of the 'propose–respond' nature of the NER framework (that is, where we must form a view on the NSP's proposed expenditure forecast). It is also necessary and appropriate to start with the NSP's proposal because the NSP is best placed to understand and provide information on its network and know what expenditure it will require in the future.⁸⁶

However, and as the MEU notes, the NSP has an incentive to prepare its proposal in a manner that allows it to increase its cost allowances.⁸⁷ Therefore, we need to test the NSP's proposal robustly. This means we must necessarily conduct our own analysis to assess its reasonableness. The AEMC has clarified that we are not limited in the techniques we may use to do this, whether they be benchmarking, information from stakeholders or anything else. The Guidelines contain the techniques we intend to use, but we may depart from the Guidelines if we consider it appropriate, with reasons. Importantly, the NER does not confine us to determining a substitute using the approach the NSP took in its proposal.⁸⁸

⁸⁰ Second reading speech, National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005, Parliament of South Australia, Hansard of the House of Assembly, 9 February 2005, p. 1452.

⁸¹ NER, clauses 6.5.6(c), 6.5.7(c), 6.12.1(3)(i), 6.12.1(4)(i).

⁸² NER, clauses 6.5.6(d), 6.5.7(d).

⁸³ NER, clauses 6.12.1(3)(ii), 6.12.1(4)(ii).

⁸⁴ AEMC, *Rule determination*, 29 November 2012, p. 112.

⁸⁵ NER, clauses 6.5.6(c), 6.5.7(c), 6.12.1(3)(i), 6.12.1(4)(i); AEMC, *Rule determination*, 29 November 2012, p. 113.

⁸⁶ AEMC, *Rule determination*, 29 November 2012, pp. 111–2.

⁸⁷ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 8–9.

⁸⁸ NER, clauses 6.12.3 and 6A.13.2; AEMC, *Final rule change determination*, November 2012, pp. 111–2.

Further, assessing the reasonableness of a NSP's proposal and determining an appropriate substitute are not separate exercises. As the AEMC clarifies, we could benchmark a NSP against its peers to form a view on whether the proposal is reasonable and what a substitute should be.⁸⁹

Therefore, we have broad discretion in how we perform our task of assessing expenditure proposals, provided we comply with the NEL and NER requirements.

3.4 Role of the Guidelines

The NER require the Guidelines to set out our approach to assessing opex and capex forecasts and the associated information requirements.⁹⁰ We have drafted the Guidelines to give effect to the legal requirements outlined in the previous sections and they provide guidance on how we will apply the legal framework when assessing proposals. This is generally consistent with the views of stakeholders.⁹¹

The Guidelines are not binding on us or NSPs, but we must state why we depart from it in making determinations.⁹² NSPs must provide with their regulatory proposals, a document complying with the Guidelines or—if we deviate from the Guidelines—the F&A paper.⁹³ The AEMC intended the Guidelines to facilitate early engagement between NSPs and the AER on how NSPs propose to forecast expenditure and the information we require to effectively assess expenditure proposals.⁹⁴ As such, we consider it appropriate to provide a level of transparency and certainty to stakeholders about the determination process. However, the Guidelines should not overly prescribe our interpretation of the legal framework and processes.

Our view is the Guidelines should remain flexible enough to account for the different circumstances that may underpin future expenditure assessments. It is not appropriate to restrict our ability to rely on certain techniques (such as economic benchmarking) in the Guidelines, for example.⁹⁵ Instead, we will use a holistic approach and use the techniques we consider appropriate depending on the specific circumstances of each determination.⁹⁶

Similarly, the Guidelines should be flexible enough for us to change information requirements as we gain further experience in implementing the changes to the NER. We will consult with the relevant parties if we are considering substantial changes to the Guidelines, as the NER require.⁹⁷

The Guidelines specify the information we require to assess expenditure. Ultimately, however, we expect to give effect to the Guidelines through RIN templates to streamline compliance for NSPs (by ensuring RINs are consistent with and encompass the F&A requirements). This is outlined in more detail in chapter 6.

⁸⁹ AEMC, *Rule determination*, 29 November 2012, p. 112.

⁹⁰ NER, clauses 6.4.5 and 6A.5.6.

⁹¹ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013 p. 7; Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, pp. 1–3; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, pp. 1, 6–7; EA Technology Australia, *Expenditure forecast assessment guidelines for electricity distribution and transmission issues paper*, 14 March 2013, p. 1; PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, pp. 4–5.

⁹² NER, clause 6.2.8(c).

⁹³ NER, clauses 6.8.2(c2) and 6A.10.1(h).

⁹⁴ AEMC, *Rule determination*, 29 November 2012, pp. 108–10.

⁹⁵ Attachment A discusses economic benchmarking in detail.

⁹⁶ AER, *Better Regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, pp. 48–9.

⁹⁷ NER, chapter 6, part G.

4 Assessment approach

This chapter outlines our assessment approach, in light of the NEL and NER requirements discussed in chapter 3. The following sections of this chapter explain:

- our general approach and the assumptions it relies on
- our approach to assessing opex
- our approach to assessing capex
- assessment techniques
- assessment principles.

4.1 General approach

For both capex and opex proposals, we use the same general approach to either accept a NSP's proposal, or not accept it and substitute it with an alternative estimate. In doing so, we will examine the NSP's proposal and other relevant information. We will apply a range of techniques that typically involve comparing the NSP's forecasts with estimates that we develop from relevant information sources.

If a NSP's total capex or opex forecast is (or components of these forecasts are) greater than estimates we develop using our assessment techniques and there is no satisfactory explanation for this difference, we will form the view that the NSP's estimate does not reasonably reflect the expenditure criteria. In this case, we will amend the NSP's forecast or substitute our own estimate that reasonably reflects the expenditure criteria.

Our general approach is not significantly different from what we applied in the past. However, we will use a broader range of assessment techniques and collect consistent data to facilitate our assessment. Consistent with our past approach, we will generally develop an efficient starting point or underlying efficient level of expenditure that we will then adjust for changes in demand forecasts, input costs and other efficient increases or decreases in expenditure. This will allow us to determine a total forecast that we are satisfied reasonably reflects the expenditure criteria.

For recurrent expenditure, we prefer to use revealed (past actual) costs as the starting point for determining efficient forecasts. If a NSP operated under an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future. The ex ante incentive regime provides an incentive to reduce expenditure because NSPs can retain a portion of cost savings (that is, by spending less than the AER's allowance) made during the regulatory control period. Consequently we apply various incentive schemes (the efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) and, going forward, the capital expenditure sharing scheme (CESS)) to provide NSPs with a continuous incentive to improve their efficiency in supplying electricity services to the standard demanded by consumers (as explained in chapter 3). We discuss incentive frameworks in more detail in chapter 5.

While we examine revealed costs in the first instance, we need to test whether NSPs responded to the incentive framework in place. For this reason, we will assess the efficiency of base year expenditures using our techniques, beginning with economic benchmarking and category analysis, to

determine if it is appropriate for us to rely on a NSP's revealed costs. That is, whether the NSP's past performance was efficient relative to its peers and consistent with historical trends.⁹⁸

We rely on revealed costs for opex to a greater extent than for capex because we assume opex is largely recurrent. Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes (particularly for transmission). For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across NSPs) when forming a view on forecast unit costs. Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

However, capex is not currently subject to an incentive scheme like the EBSS. This means that although past actual expenditures and volumes may indicate a particular NSP's likely future expenditure, we cannot presume it is efficient. We are implementing a CESS, which may mitigate this issue to some extent. Consequently, and given the presence of non-recurrent expenditures, our assessment approach is typically more involved for capex than for opex. It may be necessary to review projects and programs to inform our opinion on total forecast capex (especially for transmission).

Our approach for both opex and capex will place greater reliance on benchmarking techniques than we have in the past. We will use benchmarking to determine the appropriateness of revealed costs, for example. We will also benchmark NSPs across standardised expenditure categories to compare relative efficiency.

In some cases, we may determine that an efficient total capex or opex allowance is significantly below what the NSP has historically spent. Some stakeholders noted that if we significantly reduce a NSP's allowance, it may not be realistic for the NSP to make the necessary efficiency savings immediately; rather, a period to transition to the efficient level would be appropriate.⁹⁹ We disagree that such an approach is warranted.

We must be satisfied that the opex or capex forecast reasonably reflects the efficient costs of a prudent operator (not the NSP in question), given reasonable expectations of demand and cost inputs, to achieve the expenditure objectives. If the prudent and efficient allowance to achieve the objectives is significantly lower than actual past expenditure, a prudent operator would take the necessary action to improve its efficiency. That is, mirroring what would be expected under competitive market conditions, we would expect NSPs (including their shareholders) to wear the cost of any inefficiency rather than passing this onto consumers through inefficient or inflated prices. It is up to the NSP in question to determine how best to manage its costs within the efficient revenue allowances we set.

4.1.1 Assumptions

Our general approach is based on two assumptions:

- the efficiency criterion and the prudence criterion in the NER are complementary

⁹⁸ Attachments A and B explain in detail how we will conduct economic benchmarking and category analysis, respectively.

⁹⁹ For example, Ergon Energy raised this concern at one of the workshops. Grid Australia suggested this in its sample guideline (pp. 32–6). See also, Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 9.

- past expenditure was at least sufficient to achieve the expenditure objectives in the past.

Efficiency and prudence are complementary

Historically, we assumed efficient costs complement the costs that a prudent operator would require to achieve the expenditure objectives.¹⁰⁰ Prudent expenditure is that which reflects the best course of action, considering available alternatives. Efficient expenditure results in the lowest cost to consumers over the long term. That is, prudent and efficient expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.

Some past regulatory proposals posited that a prudent operator would apply a premium above efficient costs to balance risk.¹⁰¹ We do not agree that such an approach is consistent with the NEO. Our view is that risks ought to be borne by those best placed to meet them, and consumers are not best placed. In addition, the weighted average cost of capital compensates NSPs for non-diversifiable risk, so it is not appropriate to charge consumers a further premium on prices.

Past expenditure was at least sufficient to achieve objectives

When we rely on past actual costs to indicate required forecast expenditure, we assume that the past expenditure of either the NSP in question or other (benchmark) NSPs was at least sufficient to achieve the expenditure objectives. This assumption is appropriate because past actual expenditure indicates, for example, that at the time:

- the NSP was able to manage and operate its network in a manner that achieved the expenditure objectives (when we consider the NSP's historical expenditure is efficient), or
- other NSPs were able to manage and operate their networks in a manner that achieved the expenditure objectives, so their cost drivers should be applicable to the NSP in question, recognising differences in operating environments (when we consider the NSP's historical expenditure is not efficient).

On this basis, forecast expenditure needs to account only for changes to the efficient starting point expenditure. Accounting for such changes (including in demand, input costs, regulatory obligations and productivity) ensures the NSP receives an efficient allowance that a prudent operator would require to achieve the expenditure objectives for the forthcoming regulatory control period.

4.1.2 Assessment approaches common to opex and capex

When considering whether capex and opex forecasts reasonably reflect the expenditure criteria, we apply certain assessment approaches and use a variety of assessment techniques. Some of the approaches are specific to capex or opex. Others are common to capex and opex assessment. For example, for both capex and opex, we will always consider whether:

- forecasts are supported by economic analysis
- related party margins impact on forecast expenditure
- adjustments are required for real price escalation

¹⁰⁰ See, for example, AER, *Final decision: Victorian distribution determination*, October 2010, p. 313; AER, *Draft decision: Aurora Energy distribution determination*, November 2011, pp. 111, 156.

¹⁰¹ AER, *Final decision: Victorian distribution determination*, October 2010, p. 313.

- adjustments are required for efficient increases or decreases in expenditure (step changes).

The remainder of this section explains these common approaches in detail. We outline opex-specific and capex-specific approaches in sections 4.2 and 4.3. Section 4.4 contains detailed explanation of our assessment techniques, which are:

- benchmarking (economic techniques and category analysis)
- predictive modelling
- trend analysis
- governance reviews
- methodology reviews
- cost–benefit analysis
- detailed project review (including engineering review).

Economic justification for forecast expenditure

Economic analysis will be required to support the efficiency and prudence of forecast expenditure (economic justification). Without adequate economic justification, we are unlikely to determine forecast expenditure is efficient and prudent.

Economic justification may be highly detailed, or simplified, depending on the value of the expenditure and the uncertainty around the expenditure decision. However, in all cases it should at least demonstrate that the forecast expenditure is prudent and efficient. While not exhaustive, economic analysis supporting a given part of the forecast expenditure could include outputs from the following techniques (that will often be used in combination):

- predictive modelling (to demonstrate forecast costs and volumes are required to maintain network condition and reliability)
- trend analysis (to demonstrate forecast costs and volumes are in line with past works to maintain network condition and reliability)
- benchmarking (to demonstrate forecast volumes and/or costs are in line with outcomes achieved by other firms)
- documentation explaining procurement procedures (to demonstrate forecast volumes and/or unit costs reflect a competitive market outcome)
- engineering analysis (to demonstrate efficient and prudent expenditure options were considered when determining final projects)
- cost–benefit analysis (to demonstrate the expenditure gives the highest net benefit to achieve the outcomes desired). This will be consistent with the lowest net cost in present value terms for a given outcome. Cost–benefit analysis should also show the expenditure is cost–benefit positive unless the expenditure is legally required irrespective of the net benefit.

Generally, we consider it is likely cost–benefit analysis will be required for all material step changes and for the majority of significant capex (including material expenditure decisions related to relatively recurrent capex).

Economic justification can be contained in various documents such as business cases, financial models, and asset management plans. Irrespective of where it is contained, we expect NSPs to provide it to justify the efficiency and prudence of the forecast expenditure. Information we are likely to require from NSPs to support their proposals includes:

- clear economic analysis justifying the forecast expenditure based on need/driver, including explicit considerations of how expenditures will deliver value for consumers, as well as consideration of efficiency over the long term. This should include demonstration that material expenditure decisions (including expenditure options selected) are prudent and efficient
- an explanation of why forecast expenditure materially differs from their historical expenditure (once adjusted for changes in the volume or nature of works)
- an explanation of why forecast expenditure differs materially from their peers (once adjusted for changes in volumes and units costs based on volume and cost drivers)
- a demonstration that efficient work and efficiency trade-offs have been made, particularly with respect to choices between opex and capex
- information on forecast changes in network condition and reliability given forecast work volumes.

Related party margins

This section considers issues in assessing the efficiency of forecast expenditures to related parties. The treatment of related party margins actually paid, as it relates to calculating a NSP's regulatory asset base, is covered under our Draft Capital Expenditure Incentives Guideline.

NSPs may outsource activities to external parties to make up for a lack of internal expertise or to access economies of scope and other efficiencies (among other reasons). These external parties may be completely independent of the NSP, or they may be separate legal entities related to the NSP through common ownership ('related parties'). In some cases, a related party arrangement might exist because the parties were related at the time the transaction was made and this arrangement is difficult to unravel.

Outsourced activities are mostly network operating/maintenance and corporate services, but may also include activities related to capex, such as equipment maintenance or asset management.

In cases of related party outsourcing, the NSP's expenditure forecasts may be based on charges paid to related parties. These charges may include a margin above the direct costs incurred by the related party. Generally, we have concerns with these arrangements because NSPs may not face appropriate incentives to seek the lowest cost in negotiation with their related parties; rather they have an incentive to retain efficiency and other gains within the common ownership structure.

In the recent determination for the Victorian 2013–17 gas access arrangements, we used a conceptual framework to assess proposed expenditure that included related party contracts. The framework adopted a two-stage process for assessing such contracts.¹⁰² We propose to use this same approach to assess related party contracts and margins for electricity transmission and distribution.

¹⁰² See: AER, *Draft decision: Envestra 2013-17, Draft decision appendices, Appendix E*, 24 September 2012, pp. 101–116

The first stage acts as an initial filter. It determines which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator—the 'presumption threshold'. In assessing this presumption threshold, we consider two relevant questions:

- Did the NSP have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent renegotiation)?¹⁰³
- If yes, was a competitive open tender process conducted in a competitive market?

The second stage depends on the outcome of the first stage. If a NSP has no incentive to agree to non-arm's length terms or obtains an outsourcing arrangement through a competitive market process, we consider it reasonable to presume that the contract price reflects efficient costs and is consistent with the NEL and NER.¹⁰⁴

However, if the outsourcing arrangement was not competitively tendered, we do not consider it reasonable to assume that costs within such agreements are efficient. Such circumstances (non-arm's length, non-competitive) might influence a NSP to artificially inflate expenditures, particularly via the addition of profits or margins in addition to expenditures for direct and indirect cost recovery.¹⁰⁵ In such cases, we consider it necessary to investigate in more detail outsourcing arrangements that fail the presumption threshold. Specifically, we will consider whether:

- the total contractual cost is prudent and efficient
- outsourcing accords with good industry practice
- the costs within the contract relate wholly to providing the regulated service
- there is any double counting¹⁰⁶ of costs within the contract.

Overall assessment of contracts that fail the presumption threshold will address the following questions:

- Is the margin efficient?—The forecast costs incurred via the outsourcing arrangement are efficient if the margin above the external provider's direct costs is efficient. We consider a margin is efficient if it is comparable to margins earned by similar providers in competitive markets.
- Are the NSP's historical costs efficient?—We will benchmark the NSP's historical costs against those of other NSPs to form a view on whether the NSP's historical costs are efficient and prudent.

Efficient costs are those expected costs based on outcomes in a workably competitive market. We will need complete information on contracts that fail the presumption threshold to determine whether they reflect such efficient costs.¹⁰⁷ In line with our general category analysis, we require NSPs to assign or

¹⁰³ An indicator of potential incentives to agree to non-arm's length terms include situations when the contract was entered into (or renegotiated) as part of a broader transaction.

¹⁰⁴ The AER's reasons for presuming certain outsourcing arrangements obtained through a competitive market process are efficient and prudent are discussed in AER, *Final decision: Victorian distribution determination*, October 2010, pp. 163–303.

¹⁰⁵ AER, *Final decision: Victorian distribution determination*, October 2010, p. 150.

¹⁰⁶ This could occur where services provided under the contract include cost categories the NSP is also seeking an allowance for elsewhere in its regulatory proposal, or where there has been a transfer of risk to the contractor without a commensurate reduction in risk compensation in other elements of the NSP's building block proposal.

¹⁰⁷ We will not assess all individual contracts that fail the presumption threshold but only those that are material, in terms of costs involved and the scope/scale of services.

allocate costs arising from contracts into our individual cost categories. NSPs already engaged in related party contracts are required to provide us with expenditures including and excluding margins.

We will also require NSPs to provide other supporting information that justifies the efficiency of costs under these contracts, as well as information relevant to satisfying our presumption threshold, including:

- details/explanation of the NSP's ownership structure
- a description of the tender processes, including tender documents, bid details and tender evaluation
- a description of outsourcing arrangements
- justification of amounts paid to related parties (for example, a consultant's report on benchmarking of margins)
- copies of related party contracts
- probity reports by an external auditor on the NSP's tender process.

As we already applied this assessment approach in previous determinations,¹⁰⁸ we believe the approach is transparent and well-understood. In future resets, we will assess outsourcing contracts using the same approach, whilst consulting with NSPs and having regard to information confidentiality requirements of the NER.

Our examination of related party contracts as a specific cost item also relates to new NER requirements for treating capitalised related party margins when rolling forward the regulatory asset base (RAB).¹⁰⁹ Previously, all capex incurred was rolled into the RAB. Under the new NER, as part of ex post reviews of capex—which are required if a NSP's expenditure exceeds its forecast—we may exclude from the RAB capitalised related party margins that we assess as inflated or inefficient.¹¹⁰ Our approach to excluding margins from the RAB should be consistent with that applied when examining forecast amounts. We address this in the Capital Expenditure Incentives Guideline.

NSP submissions on the issues paper were varied in their views on our approach. Grid Australia and SP AusNet supported the use of the approach.¹¹¹ By contrast the ENA and Victorian service providers (in particular, Jemena Electricity Networks (JEN)) commented that there were flaws in the approach. They argued that the key concept should be whether the costs incurred by the regulated utility (and ultimately by customers) are higher or lower than those that would be incurred if an unrelated party contractor was used. However, they did not explain how to apply such a test in practice.

The MEU argued that outsourcing risked over-rewarding service providers, and that only benchmarking could help determine the efficient expenditure allowance. The MEU also commented that the two-stage approach is not sufficient to establish that related party margins are efficient. It contended that even competitive contracts can include unnecessary costs by carefully crafting the scope of works, and so passing the first stage does not guarantee that costs are efficient.

¹⁰⁸ AER, *Draft decision: Victorian access arrangement 2013–17, Part 3 Appendices*, September 2012, pp. 103–104.

¹⁰⁹ NER, clauses S6.2.2A and S6A.2.2A

¹¹⁰ NER, clauses S6.2.1(g), S6.2.2A, S6A.2.1(g) and S6A.2.2A.

¹¹¹ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 43; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 26.

Our proposed approach is based on our Victorian gas access arrangement review (GAAR) determination in March 2013.¹¹² The stakeholders' submissions refer only to the approach described in our December 2012 issues paper, which is a previous approach we used in the Victorian electricity determination¹¹³ and the South Australia/Queensland GAAR.¹¹⁴

Our South Australia/Queensland GAAR decision was tested in the Tribunal in a merits review of, among other things, our decision on outsourcing arrangements. The Tribunal did not find error with our decision that a detailed assessment of the outsourcing contract¹¹⁵ was required, given incentives for non-arm's length arrangements. The Tribunal also considered that the two-stage test may be an appropriate vehicle for this type of analysis. Therefore we will continue with a two-stage approach in assessing outsourcing contracts and, for contracts that fail the first stage, review these contracts in detail. Detailed assessments will include benchmarking to determine the efficient expenditure allowance, as supported by the MEU.

However, contrary to the MEU's view, we consider that the contract price is likely to be a good proxy for the competitive market price if the outsourced services were subject to a competitive tender process. If the outsourced services were provided via competitive tender in a competitive market, there can be a reasonable degree of assurance that these services are being provided efficiently, and that the prices charged for these services reflect a competitive market price. If, however, we have cause to consider that there were deficiencies in the tender process, we will move away from this presumption and conduct further examination.

Real price escalators

Input prices paid by NSPs may not change at the same rate as the consumer price index. In recent years, strong competition for labour from related industries (such as the mining sector) resulted in strong labour price growth in many states. The commodities boom also saw the price of raw materials rise significantly. This in turn influenced the prices of the materials purchased by NSPs. Further, the Australian dollar has been at record highs until recently, lowering the price of imports. All of these factors, and others, have made it more difficult to forecast the costs NSPs face for the inputs they use.

Labour price changes

Labour costs represent a significant proportion of NSPs' costs and thus labour price changes are an important consideration when forecasting expenditure. This is particularly true for opex, which can mostly comprise labour costs. We expect the wage price index¹¹⁶ (WPI) published by the Australian Bureau of Statistics (ABS) will remain our preferred labour price index to account for labour price changes over the forecast period.

When forecasting the impact of labour price changes, it is important to distinguish between labour price changes and labour cost changes. To the extent labour prices increase to compensate workers for increased productivity, labour costs will not increase at the same rate since less labour is required to produce the same output. Consequently, unless labour productivity improvements are captured elsewhere in expenditure forecasts, forecasts of changes in labour prices should be productivity

¹¹² AER, *Draft decision: Victorian access arrangement 2013–17, Part 3 Appendices*, September 2012, pp. 103–104.

¹¹³ AER, *Final decision: Victorian distribution determination*, 29 October 2010, pp. 298–303.

¹¹⁴ AER, *Draft decision: Queensland gas access arrangement review final decision 2011–16*, February 2011, pp. 131–136; and AER, *Draft decision: South Australia gas access arrangement review final decision 2011–16*, February 2011, pp. 131–136.

¹¹⁵ Envestra SA's outsourcing contract with the APA Group

¹¹⁶ Previously called the labour price index (LPI).

adjusted. For the reasons discussed in section 4.2, our preferred approach is to apply a single productivity measure in the forecast rate of change. This productivity measure would include forecast labour productivity changes. Consequently forecast increases in the labour price would not need to be productivity adjusted under this approach.

Another important, and related, consideration is the choice of labour price measure, namely the WPI or average weekly ordinary time earnings (AWOTE), which is also reported by the ABS. One key difference between these two measures is the AWOTE measure includes compositional labour change, as was noted in the working group meeting on 8 May 2013.¹¹⁷ That is, AWOTE captures the price impact of using more or less higher skilled labour. In that working group meeting NSPs queried whether AWOTE or the WPI was the AER's measure of choice.¹¹⁸ We preferred to use the WPI because including compositional labour changes tends to increase the volatility in the AWOTE series, making it more difficult to forecast. We expect the WPI will remain our preferred labour price index. However, to the extent expenditure forecasts are adjusted using a productivity measure that matches the labour price measure, the impact of the labour price measure choice should be reduced.

A further consideration is the source of the forecasts used. The forecasts produced for the AER have often varied significantly from the forecasts produced for and proposed by the NSPs. In working group meetings, consumer representatives urged the AER to review the accuracy of price forecasts.¹¹⁹ We have tested the accuracy of labour price forecasts in the past. We will continue to analyse the labour price forecasters' past performance when determining the appropriate labour price forecasts to rely on.

Materials price changes

Materials price changes are an important driver of costs, particularly capex, given their potential volatility. As Ergon Energy noted:

Materials are often purchased on the basis of large, long-term contracts, and due to the specialised nature of the equipment, are exposed to currency and other fluctuations that will not necessarily align with local economic drivers.¹²⁰

Further, the ENA noted the inputs used by the NSPs are often industry specific, so prices can diverge from the input prices of other industries.¹²¹

For a number of resets now, we (and NSPs) used an input price modelling approach to forecast materials costs. This approach forecasts the cost of the inputs used to manufacture the materials (such as copper aluminium and steel) and assigns input weightings to generate a forecast of the cost of those materials. Now that this forecasting approach has been in place for a number of years we think it is an appropriate time to review how well it has worked. Although evidence is readily available to assess the accuracy of our approach to forecasting input costs, we have seen limited evidence to demonstrate that the weightings applied have produced unbiased forecasts of the costs the NSPs

¹¹⁷ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 4.

¹¹⁸ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 4.

¹¹⁹ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 4.

¹²⁰ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 17.

¹²¹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, Attachment B, p. 9.

paid for materials. We consider it important that such evidence be provided because, as stated by the ENA:

...the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used. Consequently, the price of manufactured network materials may not be well correlated with raw material costs.¹²²

Consequently, we expect NSPs to provide evidence of the materials costs they paid in their regulatory proposals. They must demonstrate the proposed approach they chose to forecast materials cost changes reasonably accounted for changes in prices they paid in the past.

Step changes

We are required to determine capex and opex forecasts that reasonably reflect the efficient costs a prudent operator would require to achieve the expenditure objectives. The expenditure objectives include compliance with regulatory obligations or requirements. Regulatory obligations or requirements may change over time, so a NSP may face a step up or down in the expenditure it requires to comply with its obligations.

Another important consideration is the impact of the forecast capital program on opex (and vice versa), since there is a degree of substitutability between capex and opex. A NSP may choose to bring forward the replacement of certain assets (compared to its previous practice) and avoid maintenance expenditure, for example. Such an approach may be prudent and efficient.

In line with past practice, our likely approach is to separately identify and assess the prudence and efficiency of any forecast cost increases associated with new obligations and other step changes. We may use several techniques to do this, including examining the economic analysis justifying the investment/expenditure decisions and technical expert review of the inputs into this analysis.

To justify additional costs for a new obligation NSPs must show:

- there is a binding (that is, uncontrollable) change in obligations that affects their efficient forecast expenditure
- when this change event occurs and when it is efficient to incur expenditure to comply with the changed obligation
- the options considered to meet the change in legal obligations and that they selected an efficient option—that is, the NSP took appropriate steps to minimise its cost of compliance from the time the event was foreseeable
- when they can be expected to make the changes to meet the changed legal obligations
- the efficient costs associated with making the step change
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts.

Forecast expenditure (including volumes and cost of different categories of works) related to any changes in obligations, or other step changes (for example, due to efficient capex opex trade-off), should be reported as such in the relevant category of opex and capex.

¹²² Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, Attachment B, p. 9.

We consider the following general points can be made about our expected assessment of step changes:

- We will approve expenditure for works we consider can be completed over the regulatory period. This is consistent with our past approach if we considered the NSP will be unable to meet an obligation within the regulatory period.
- We will only approve expenditure based on efficient timing of works. This is consistent with past decisions if we considered it inefficient to complete works over the regulatory period. Therefore, when there is a binding legal timeframe for compliance, NSPs should show they selected efficient expenditure timing to comply with the legal timeframe. Where obligations have no binding timeframe for compliance, works should be undertaken when efficient to do so.

We expect to make two changes to past assessment practice:

- Under the base-step-trend approach to setting opex, step changes caused by incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for high costs resulting from changed obligations. Under this approach, only changes in costs that demonstrably do not reflect historic 'average' changes will be compensated as separate step changes in forecast opex. An example of something demonstrably different would be the higher costs associated with vegetation management due to regulatory changes following the Bushfire Royal Commission in Victoria.
- For category assessments generally (i.e. capex as well as base year opex), we will require NSPs to separately identify step changes for changes in obligations against the core expenditure categories (for example, augmentation, replacement, vegetation management). Previously, NSPs reported, and we assessed, some step changes as part of a separate environment, safety and legal expenditure category. We consider it is important to report and assess changes in obligations in the context of the core category they affect. This will ensure a consistent assessment approach is applied to all NSPs.

NSPs will be expected to justify the cost of all step changes with clear economic analysis, including quantitative estimates of expected expenditure associated with viable options. We will also look for the NSPs to justify the step change by reference to known cost drivers (for example, volumes of different types of works) if cost drivers are identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for NSPs to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

Stakeholders commented that the cost of a given change in obligations will differ between NSPs¹²³ and it can be difficult to capture the incremental cost of a change in obligations for an existing activity.¹²⁴ Aurora commented that expenditure associated with a changed regulatory obligation

¹²³ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 6; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 16; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B - Category analysis*, 15 March 2013, p. 6.

¹²⁴ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 16; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B - Category analysis*, 15 March 2013, p. 6.

cannot be disaggregated in a way that will improve accuracy in forecasting and efficiency assessments.¹²⁵ Grid Australia considered it would be difficult to determine sub categories of expenditure that will assist with forecasting changes in regulatory obligations, and individual businesses are best placed to identify the costs required to meet changes in obligations. It considered the AER should assess the impact of changes on TNSPs during a regulatory determination process based upon the individual circumstances of the TNSP and information provided by it.¹²⁶ The MEU commented that benchmarks need to be assessed on a common basis and therefore step changes must be identified and adjusted for in historical benchmarks. Adjusted benchmarks should then be refined as actual costs are revealed over time.¹²⁷ One NSP queried whether the short term costs to achieve dynamic efficiency gains could be claimed as step changes.¹²⁸

NSPs also queried how the AER would measure the impact of ongoing changes in regulatory burden in historic data including:

- how to determine the 'base level' of regulation
- how to determine material increases in regulatory costs over time
- whether CPI could be used as a proxy for increases in regulatory burden over time.¹²⁹

NSPs also queried whether they would be adequately compensated for all step changes if changes in regulatory burden over time were captured in the productivity measure.¹³⁰

We consider the cost of a given change in obligations may differ between NSPs depending on the nature of the change. However, we expect the NSPs to justify their forecast expenditure and quantify the incremental costs associated with changes in existing obligations. Where step changes materially affect historical benchmarks we may make adjustments to the historical benchmarks to account for these changes.

Whether short-term costs to achieve dynamic efficiency gains should be allowed as step changes depends on NSPs already being adequately compensated for these costs under the regulatory regime, including via compensation under any incentive schemes. We expect NSPs to bear any short-term cost of implementing efficiency improvements in expectation of being rewarded through expenditure incentive mechanisms such as the EBSS.

To the extent that changes in regulatory burden are already compensated through the productivity measure, they will not be compensated again explicitly as step changes. We will consider what might constitute a compensable step change at resets, but our starting position is only exceptional events are likely to require explicit compensation if we use a productivity measure that captures regulatory change over time.

¹²⁵ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 21.

¹²⁶ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 38.

¹²⁷ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp 35–6.

¹²⁸ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 6.

¹²⁹ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 6.

¹³⁰ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, pp. 6–7.

Where businesses do not justify step changes sufficiently, we may use the historical expenditure, adjusted for cost and volume drivers, as a basis for determining an efficient level of forecast expenditure if we consider this gives a reasonable estimate. NSPs will need to perform a cost–benefit analysis to show that meeting standards that have not been met before is efficient and prudent. If new smart electricity meters showed extra non-compliance with voltage standards relative to current reporting and investigation procedures, for example, we will be likely to require a cost–benefit analysis to show any augmentation (materially in excess of current levels) to comply with the current standards was efficient and prudent. This is consistent with our past practice.

4.2 Opex approach

We intend to adopt the same approach to assessing opex forecasts as we have in the past. However, we also intend to use a broader range of assessment techniques and to collect consistent data to aid our assessment.

Consistent with past practice, we prefer a ‘base-step-trend’ approach to forecasting most opex cost categories (which assumes opex is largely recurrent). As explained above, if a NSP has operated under an effective incentive framework, and sought to maximise its profits, the actual opex incurred in a base year is a good indicator of the efficient opex required. However, we must test this, and if we determine that a NSP’s revealed costs are not efficient, we will adjust them to remove the inefficient costs. Details of our base year assessment approach are below.

Once we have assessed the efficient opex in the base year we then account for any changes in efficient costs in the base year and each year of the forecast regulatory control period. There are several reasons why efficient opex in a regulatory control period could be different from the base year. Typically, we will adjust base year opex for:

- output growth
- real price growth
- productivity growth
- other efficient expenditure not included in base opex.

The first three factors will be incorporated through an annual ‘rate of change’. Any other costs that would meet the opex criteria but are not compensated for in the rate of change can be added as a step change.

We outlined this proposed approach to assessing opex forecasts in a working group meeting on 8 May 2013.¹³¹ Generally, comments from stakeholders focused on the new or refined aspects of our opex forecasting approach, being:

- our assessment of base opex and whether we rely on revealed costs
- how productivity improvements will be forecast and treated
- what forecast costs should be treated as step changes.

¹³¹ AER, ‘Meeting summary - NSP reliance on actual data, base step & trends, productivity change’, *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013.

4.2.1 Assessing base opex

If actual expenditure in the base year reasonably reflects the opex criteria we will set base opex equal to actual expenditure.¹³² We will likely apply all of our assessment techniques to assess whether base opex reasonably reflects the opex criteria. This section on base opex assessment should be read in conjunction with section 5.3 as it relates to incentives under the EBSS.

If we identify material inefficiencies in actual base year expenditure we will not use it as base opex. In this case, we will consider two options for base opex:

1. using a different year of actual expenditure for base opex that does reasonably reflect the opex criteria
2. adjusting actual base year expenditure so it reasonably reflects the opex criteria.

If we find base opex does require adjustment, we will likely apply all of our techniques to determine the adjustment. Further, when determining whether to adjust or substitute base year expenditure, we will also have regard to whether rewards or penalties accrued under the EBSS will provide fair sharing of efficiency gains or losses between the NSP and its customers. The operation of the EBSS will be an important consideration in our assessment of base opex.

A NSP should be largely indifferent in the choice of base year. Although a different base year will derive a different opex forecast, any change to the opex forecast should be offset by a similar but opposite change to the increment/decrement accrued under the EBSS. That is, the opex forecast, net of any EBSS carryover, should be similar.

NSPs raised concerns about departing from a revealed cost approach and relying more on benchmarking to determine base opex. The Public Interest Advocacy Centre (PIAC), however, considered there was no evidence that NSPs were responding to incentives and hence the presumption that revealed costs were efficient should not be accepted.¹³³ As we discuss further in chapter 5, we agree with PIAC's view, and we will test the efficiency of revealed costs before accepting them. Our proposed approach to conducting benchmarking is discussed in Attachments A (economic benchmarking techniques) and B (category analysis). Considerations generic to assessments of particular expenditure categories (including opex) are also contained in section 4.3.1 below. Chapter 5 further discusses how the determination of base opex impacts the opex incentive.

We are now explicitly required to have regard to whether an opex forecast is consistent with any incentive schemes that apply to a NSP.¹³⁴ In turn, in developing and implementing the EBSS, the AER must have regard to the need to provide NSPs a continuous incentive to reduce opex.¹³⁵ Because final year opex will not be known when the AER makes a final determination, efficiency gains made in that year cannot be incorporated in the EBSS. To provide the same opex incentive in the final year we assume no cumulative efficiency gain is made after the base year. To ensure continuous incentives, we must make the same assumption in setting the opex forecast. For this reason, we will assume final year expenditure is equal to:

¹³² We may not use the revealed cost approach to forecast all cost categories. For example, we typically forecast debt raising costs based on the costs of a benchmark firm.

¹³³ PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, p. 6.

¹³⁴ NER clauses 6.5.6(e)(8) and 6A.6.6(e)(8).

¹³⁵ NER clauses 6.5.8(c)(2) and 6A.6.5(b)(1).

$$\text{Deemed final year opex} = F_f - (F_b - A_b)$$

where:

- F_f is the determined opex allowance for the final year of the preceding regulatory control period
- F_b is the determined opex allowance for the base year
- A_b is the amount of actual opex in the base year.

This deemed final year opex (taking into account an efficiency adjustment, if required) is then used to forecast opex for the following regulatory control period by applying the rate of change. This ensures that any efficiency gains made after the base year are retained only for the determined carryover period.

4.2.2 Assessing productivity

Forecast productivity change will be incorporated in the annual 'rate of change' we apply to base opex. The forecast productivity change will be our best estimate of the shift in the productivity frontier.

We are required to provide NSPs with an opex forecast that reflects the efficient costs of a prudent firm.¹³⁶ To do this we will need to forecast the productivity improvements it is reasonable to expect that firm can achieve. This is consistent with the productivity improvements an efficient firm operating in a competitive market would be able to retain. All else equal, a price taker in a competitive market will maintain constant profits if it matches the industry average productivity improvements reflected in the market price. If it is able to make further productivity improvements, it will be able to increase its profits until the rest of the industry catches up, and this is reflected in the market price. Similarly, if a NSP is able to improve productivity beyond that forecast, it is able to retain those efficiency gains for five years through the EBSS.

One of the refinements to our opex assessment approach will be how we incorporate productivity improvements into our opex forecasts. Previously, we did not forecast a single productivity measure. This created a risk of double counting productivity gains when economies of scale and labour productivity were considered, for example. As a result, we only applied economies of scale to output growth escalation.

Over time, we intend to develop a single productivity forecast through econometric modelling of the opex cost function (see Attachment A). Applying this single productivity forecast avoids the risk of double counting productivity growth. Another advantage of this approach is that it should be more transparent than our previous approach.¹³⁷ However, if the productivity adjustment is to reflect the potential productivity change the NSP can achieve in the next regulatory control period, it should be:

1. firm-specific
2. considered in combination with any base year adjustment.

The proposed new approach addresses the first point by enabling us to derive a productivity forecast specific to the NSP by incorporating:

¹³⁶ NER clauses 6.5.6(c)(1), 6.5.6(c)(2), 6A.6.6(c)(1) and 6A.6.6(c)(2).

¹³⁷ AER, 'Meeting summary- Expenditure setting process and general issues', *Workshop 18: General guideline consultation - Expenditure setting process and general issues*, 13 June 2013, p. 3.

- forecast output growth
- forecast changes in NSP specific business conditions
- forecast technological change.

However, consideration of the second point introduces some complexities that need to be considered. The forecast productivity change of an efficient individual NSP can be disaggregated into ‘catching up to the frontier’ and frontier shift. Any base year adjustment we apply will capture any catch up required. Thus the forecast productivity change included in the rate of change should represent the forecast shift in the productivity frontier.

Estimating productivity frontier shift

Consequently, we need to be able to decompose our productivity change measure into the sources of productivity change to separately apply the base year adjustment and productivity forecast. We propose to do this by:

- having regard to TFP differential in the base year together with information from category analysis benchmarking to gauge the scope of inefficiency to be removed by the base year adjustment
- using the TFP change of the most efficient business (or highly efficient businesses as a group) to gauge the scope of further productivity that may be achieved by individual businesses—this assumes that relevant drivers (such as technical change and scale change) and their impact remain the same over the two periods considered (historical versus forecast).

We are particularly interested in stakeholders' views on this proposed approach and any alternative approaches.

For some NSPs, future productivity gains may be substantially different from what they achieved in the past. For example, inefficient NSPs may significantly improve productivity and become highly efficient at the end of the sample period. This would reduce the potential for them to make further productivity gains in the following period. Further, using a NSP's own performance to forecast future productivity gains will reduce its incentive to improve productivity, since it will reduce future revenues. We will be mindful of these issues when we forecast future productivity changes.

Similar issues apply to the productivity change achieved by the industry as a whole. If the group includes both efficient and inefficient NSPs, the industry-average productivity change may be higher than what an individual NSP can achieve. To the extent inefficient NSPs are catching up to the frontier, the industry average productivity change will include both the average moving closer to the frontier and the movement of the frontier itself. NSPs raised this issue in workshops, stating it would be unreasonable to assume a frontier firm could match the industry average productivity growth if the rest of the industry was getting closer to the frontier.¹³⁸

4.2.3 Assessing step changes

There can be some cost changes that would reasonably reflect the opex criteria but would not be captured by the rate of change. For this reason, we will also add step changes to our opex forecast where they are necessary to produce a forecast that is consistent with the opex criteria. Our general

¹³⁸ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, pp. 3–4.

approach to assessing step changes is discussed in section 4.1.2. Here we discuss considerations specific to the rate of change forecasting approach.

Step changes should not include the forecast costs of a discretionary change in inputs (other than for capex/opex trade-offs, which are discussed in section 4.3.1). Since the rate of change incorporates output growth and price growth, any step change for an increase in the cost of inputs would represent a reduction in productivity. We do not consider this would be consistent with the opex criteria. However, if the driver for the step change is out of the NSP's control, then it may be consistent with the opex criteria. For example, if the step change was for the costs to meet a new regulatory obligation, it may be appropriate to provide a step change; forecast opex should provide sufficient expenditure to comply with all applicable regulatory obligations or requirements.¹³⁹

However, the productivity measure included in the rate of change may compensate the NSP for past regulatory changes. If forecast productivity is derived from the historical change in outputs and inputs, the derived productivity forecast will be net of productivity losses driven by the increased inputs required to meet new regulatory obligations imposed over the sample period.

Thus, if the forecast increase in the regulatory burden over the regulatory control period is consistent with the increase in regulatory burden over the sample period used to forecast the productivity change, step changes would not be required for new regulatory obligations. The difficulty of determining the productivity impact of past regulatory obligation changes was noted by all stakeholders at working group meetings.¹⁴⁰ In reflection of this, we have not specified a particular assessment approach or data requirements of NSPs at present. However we consider it must be accounted for when assessing NSPs' opex forecasts. Otherwise, applying productivity in the rate of change and adding step changes would overstate the prudent and efficient opex required.

4.3 Capex approach

We intend to adopt the same general approach to assessing total forecast capex as we have used in the past. However, we intend to use a broader range of assessment techniques and to collect consistent data to aid our assessment. We consider improved data will make these processes more effective and efficient when assessing forecast capex. We also consider some standardisation of process and data should make preparing and assessing revenue proposals simpler.

The key changes likely to affect the assessment of capex relative to the status quo are:

- a greater requirement for the economic justification of expenditure and increased data requirements to support proposals
- the use of top down economic benchmarking and greater category level benchmarking
- the introduction of a CESS.

Elements of the capex assessment process will include:

- reviewing the economic justification for expenditure
- reviewing the expenditure forecasting methodology and resulting expenditure forecasts

¹³⁹ NER clause 6.5.6.(a)(2), 6A.6.6(a)(2).

¹⁴⁰ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, pp. 4–5.

- top down economic benchmarking
- reviewing governance and policies
- trend analysis
- category benchmarking
- targeted review of high value or high risk projects and programs
- sample review of projects and programs and applying efficiency findings to other expenditure forecasts.

The remainder of this section covers developing expenditure categories based on cost drivers and assessing risk factors applicable to transmission capex forecasts. The techniques used in our assessments are covered in section 4.4. The overlap with the CESS is covered in chapter 5.

4.3.1 Categories for capex assessment

We will examine forecast work volumes and costs in the context of the different capex drivers. To do this, we will split capex into high level, standardised subcategories that reflect primary capex drivers. The high level subcategories are likely to be in line with past practice:

- repex
- augex
- connection and customer driven works capex
- non-network capex.¹⁴¹

We consider these categories have distinct expenditure (unit cost and volume) drivers and should be examined independently for this reason. They are also consistent with the expenditure drivers identified in the issues paper and accommodate stakeholder comments made at workshops.¹⁴² We may further disaggregate these categories via distinct expenditure drivers.

By considering expenditure at the subcategory and lower levels, we can better examine the prudence and efficiency of a NSP's proposed expenditure. In many situations, quantitative relationships should exist between expenditure drivers and forecasts, and may be used to estimate prudent and efficient future expenditure. Using standardised lower level subcategories should also allow direct comparison of forecast with benchmark figures based on other NSPs' performance. This should help us form a view about whether the total forecast capex reasonably reflects the capex criteria. We also consider this information should allow NSPs to identify potential areas of inefficiency in their operations and target these areas for performance improvement.

The majority of stakeholders supported the expenditure drivers in our issues paper,¹⁴³ although many noted the list was not exhaustive. Grid Australia noted the terminology used in transmission is slightly

¹⁴¹ Note the considerations in this section are equally applicable to analysis of opex categories, which are also detailed in Attachment B.

¹⁴² AER, Expenditure forecast assessment guidelines Issues paper, Dec 2012, p. 97; AER, 'Meeting summary - Selection of expenditure categories', *Workshop 2: Category analysis work-stream - Category selection (Transmission and Distribution)*, 28 February 2013.

¹⁴³ Energex, *Energex response to AER's Expenditure forecast assessment guidelines for electricity distribution and transmission - Issues Paper*, 15 March 2013, p. 1; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*,

different, although the drivers they identified appear consistent with our high level expenditure categories.¹⁴⁴

Despite stakeholders' general agreement, many identified issues they considered must be addressed. Aurora Energy questioned the merit of attempting to derive quantitative relationships between expenditure and drivers, given the complexities of distribution networks.¹⁴⁵ Several stakeholders also questioned if lower levels of aggregation would lead to more robust benchmarking and quantitative analysis.¹⁴⁶ By contrast, some stakeholders supported developing quantitative relationships between expenditure categories and cost drivers,¹⁴⁷ although the ENA noted we must ensure we have identified all cost drivers so a NSP is funded to meet all of its obligations.¹⁴⁸ SP AusNet considered derivations of quantitative expenditure driver relationships were likely to be more applicable to DNSPs than TNSPs.¹⁴⁹ The MEU supported our proposed approach to examining direct costs for various activities because they relate to cost drivers. They also considered common disaggregation at the cost centre level would not impose excessive burden on business.¹⁵⁰

A number of NSPs submitted that comparability of expenditure across businesses is an issue due to differences in business characteristics.¹⁵¹

Several stakeholders submitted that category disaggregation should be not greater than the business uses to manage its own costs,¹⁵² while Energex considered clear reporting definitions would be required to ensure consistent application across DNSPs.¹⁵³

We remain of the view that different types of expenditure have different drivers. We also consider quantitative relationships for expenditure can be analysed and benchmarked in many situations.

We consider that lower level analysis will allow us to better control for differences across businesses in many situations and to understand how expenditure is affected by the different cost drivers a business faces. We also disagree with the proposition that disaggregation should be not greater than

¹⁴⁴ Australian Energy Regulator, 15 March 2013, pp. 13–4; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B - Category analysis*, 15 March 2013, p. 1; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 23; United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator*, 19 March 2013, p. 14. Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, pp. 28–9.

¹⁴⁵ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 6.

¹⁴⁶ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 10; PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, p. 12;

¹⁴⁷ PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, p. 11; Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 13; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 11.

¹⁴⁸ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 13.

¹⁴⁹ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 12.

¹⁵⁰ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 15–6.

¹⁵¹ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 10; United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator*, 19 March 2013, p. 14.

¹⁵² Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 10; Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 14.

¹⁵³ Energex, *Energex response to AER's Expenditure forecast assessment guidelines for electricity distribution and transmission - Issues Paper*, 15 March 2013, p. 1.

a business uses to manage their costs as we have found that we require different information to furnish our assessment techniques (the prime example being breakdown of major contract costs).

We agree it is critical that reporting categories need to be clearly defined for data to be comparable across NSPs and consider this is likely to be an ongoing process of refinement.

We acknowledge that the list of drivers was not exhaustive and firms have different characteristics that influence their efficient and prudent costs. However, we consider the key drivers identified support our suggested categorisation and approach to category based analysis and differences in efficient and prudent costs can be identified and allowed for.

We are aware of the cost trade-offs between categories of work and between capital and operating expenditures. To avoid perceived 'cherry picking' we intend to consider potential trade-offs when examining category level forecast expenditure when setting an overall regulatory allowance.

Attachment B provides more detail on our likely assessment approach specific for each capex subcategory.

4.3.2 Cost estimation risk factors (transmission only)

Cost estimation risk factors (risk factors) are typically a component of a TNSP's methodology for forecasting capex. In previous determinations, we acknowledged that TNSPs face uncertainty when developing their capex forecasts, and invariably there is a difference between what TNSPs forecast for particular project cost items and what they actually incur.

Our objective is to standardise the way we assess TNSPs' risk factor estimates. Our assessment approach will remain largely the same as the approach we used in recent determinations and will involve reviewing:

- information TNSPs provide to support the risk factor, including any consultant advice
- comparisons of TNSP project specific actual and expected capex
- any consultant advice commissioned by the AER.

We will require TNSPs to substantiate their proposed risk factors for the projects they propose by demonstrating they:

- identified the risks to estimation (both upside and downside)
- developed strategies to mitigate any downside risks
- quantified the uncertainty that remains after implementing the mitigation strategies.

TNSPs are required to identify both the risks to the cost estimates and the potential mitigation strategies applicable to each project. We consider there are two types of risk to project estimates:

- Inherent risks represent uncertainty associated with the cost build-up of the project. This is borne out of assumptions used in estimating the unit cost and volumes of the inputs for the project.
- Contingent risks represent uncertainty created by events outside the cost build-up estimate. These events can include unforeseen weather impacts, industrial action, safety, planning approval, design development. Typically, TNSPs included a contingent allowance in their cost build up, effectively an amount added to each project accounting for identifiable contingent risks.

After identifying these risks TNSPs will be required to quantify the residual risk that remains after implementing the relevant mitigation strategies. We consider this residual is the risk factor that applies to the TNSPs capex forecast. TNSPs must demonstrate they followed this process in supporting information substantiating their proposed risk factor estimate.

We consider TNSPs should have discretion to the methodology they use to estimate the risk factor, given the complex and discrete nature of the transactions involved.

We consider there to be greater uncertainty for TNSPs than DNSPs in estimating project costs because:

- transmission projects typically involve longer planning and construction lead times than distribution projects. This lag may result in greater divergence between the assumptions used in the forecast and the actual cost because circumstances change
- transmission projects may be unique or with limited precedent compared with distribution projects. Hence cost items used in the estimation process may be based on relatively less experience
- DNSPs' capex programs involve more projects, reducing the risk of any individual project on overall capex outcomes because of diversification.

In previous determinations, we only recognised risk factors in projects at the concept phase of the project lifecycle. TNSPs should also carefully consider the following issues we were concerned about in the past:

- the process undertaken to identify the risks to the estimates and the extent to which this process can be independently verified
- the portion of the identified risks consumers should bear in accordance with the NEL
- potential double counting of real price escalators, pass through events and other contingencies which are compensated for elsewhere in our determinations
- the extent to which the TNSP has (or should have) improved its ability to forecast its capex over time
- the time period between the forecast preparation and project completion
- the period of the project lifecycle (for example, the concept phase)
- the robustness of the data used to generate the risk factor estimate.

In submissions responding to our issues paper, the ENA noted that TNSPs apply varying techniques to build up specific project budgets. It did not advocate prescribing a particular methodology to account for these risks, noting that this depends on the cost estimating methodology the NSP used.¹⁵⁴ Ergon Energy emphasised that TNSPs forecast capex based on estimates for projects, many of which are only in concept phase and are subject to change.¹⁵⁵ We recognise that TNSPs are better able to identify the unique circumstances affecting their forecasts, and there is unlikely to be any one correct

¹⁵⁴ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 9.

¹⁵⁵ Ergon Energy Corporation Limited, *Submission on the Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission Issues Paper Australian Energy Regulator* 15 March 2013, p. 18.

estimation method. For these reasons, we have not proposed to develop a prescriptive risk factor estimation methodology.

Our issues paper asked for stakeholders' views on the materiality of optimism bias or strategic misrepresentation. The ENA supported strong incentive schemes to drive efficient levels of expenditure, which would then be accounted for in determining expenditure forecasts. It considered this removes concern that using risk factors developed from past inefficient actual expenditures inflates forecasts.¹⁵⁶ Ergon Energy did not consider strategic misrepresentation to be an issue under the current NER regime. It further noted that when considering the cost build-up of projects, estimates will contain bias depending on the degree of detail available at that time.¹⁵⁷ JEN stated that strategic misrepresentation or bias would require a company officer to make a false statutory declaration to the AER, which is highly unlikely, given the personal and professional implications of such conduct.¹⁵⁸

We acknowledge that it is unlikely TNSPs will be able to explicitly account for strategic misrepresentation. We do expect them, however, to consider the extent to which bias may exist in the estimation process, particularly given historical information and the particular circumstances that gave rise to project cost over-runs.

4.4 Assessment techniques

When we assess capex and opex forecasts, we may use a number of assessment techniques, often in combination. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but in general, we will follow an assessment filtering process. That is, we will apply high level techniques in the first instance and apply more detailed techniques as required. For example, for the first pass assessment, we will likely use high level economic and category level benchmarking to determine relative efficiency and target areas for further review. We will, however, also use benchmarking techniques beyond the first pass assessment.

The first pass assessment will indicate the extent we need to investigate a NSP's proposal further. Typically, we will apply predictive modelling, trend analysis and governance or methodology reviews before delving into detailed techniques such as cost-benefit analysis and project or program review. While we intend to move away from detailed techniques such as project reviews, we are likely to rely on them in some cases, particularly to assess capex for TNSPs.

We intend to take a holistic approach and consider the inter-connections between our assessment techniques when determining total capex and opex forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques. For example, benchmarking analysis may indicate that a DNSP's unit cost for transformers at zone substations is high relative to other DNSPs. We would not simply adjust the expenditure forecast for zone substations by applying the benchmark unit cost without reference to the other assessment techniques we have used. For example, any inference we may make about expenditure on transformers and/or zone substations might also consider analysis from other techniques such as the augex model or detailed review. In addition, we will provide the NSP the opportunity to explain the result of the benchmarking analysis.

This section explains our assessment techniques, which are:

¹⁵⁶ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 10.

¹⁵⁷ Ergon, Energy Corporation Limited, *Submission on the Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission Issues Paper Australian Energy Regulator* 15 March 2013, p. 17.

¹⁵⁸ Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 13.

- benchmarking (economic techniques and category analysis)
- methodology review
- governance and policy review
- predictive modelling
- trend analysis
- cost–benefit analysis
- detailed project review (including engineering review).

4.4.1 Benchmarking

Benchmarking compares standardised measurements from alternative sources. We will be using benchmarking techniques more widely than in the past.

Economic benchmarking

Economic benchmarking applies economic theory to measure the efficiency of a NSP's use of inputs to produce outputs, having regard to environmental factors. It will enable us to compare the performance of a NSP with its own past performance or the performance of other NSPs.

We propose to take a holistic approach to using economic benchmarking techniques but intend to apply them consistently. We will determine which techniques to apply at the time of determinations, rather than specify economic benchmarking techniques in our Guidelines. This will allow us to refine our techniques over time.

In determinations, we will use economic benchmarking models based on their intended use, and the availability and quality of data. Some models could be used to cross-check the results of other techniques. At this stage, it is likely we will apply multilateral total factor productivity (MTFP), data envelopment analysis (DEA) and an econometric technique to forecast opex. We anticipate including economic benchmarking in annual benchmarking reports.

We are likely to use economic benchmarking to (among other things):

1. measure the rate of change in, and overall, efficiency of NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.
2. develop a top down total cost forecast of total expenditure.
3. develop a top down forecast of opex taking into account:
 - the efficiency of historical opex
 - the expected rate of change for opex.

Economic benchmarking will also indicate the drivers of efficiency change which will assist us in targeting our expenditure reviews. We consider economic benchmarking (including submissions) in more detail in Attachment A.

Category level benchmarking

Category level benchmarking allows us to compare expenditure across NSPs for categories at various levels of expenditure. It can inform us, for example, of whether a NSP's:

- base expenditure can be used for trend analysis
- forecast unit costs are likely to be efficient
- forecast work volumes are likely to be efficient
- forecast expenditure is likely to be efficient.

Category level benchmarking may also provide information to NSPs on where they may achieve efficiencies in their operations. For these reasons, we consider category benchmarking is justified as it should improve the effectiveness of our assessment and may assist NSPs in improving their operations over time.

We received several submissions about benchmarking. Some questioned the effectiveness of benchmarking given the exogenous differences across NSPs and the differences in data collection¹⁵⁹ and the risks of applying simplistic models in light of this.¹⁶⁰ They also questioned the value of collecting information and if the benefits from the extra data would outweigh the costs associated with its collection.¹⁶¹ They also questioned the consistency of using the proposed benchmarking with incentive regulation.¹⁶² Generally, submissions indicated benchmarking should be used to target further assessment¹⁶³ and should not be used in a determinative way¹⁶⁴ or for setting expenditure allowances.¹⁶⁵

The MEU supported benchmarking to drive efficiencies in costs, although it noted it is unrealistic to reduce actual costs in a short period of time.¹⁶⁶

PIAC supported developing disaggregated benchmarking, although it noted that high level benchmarking may ultimately prove to be a more useful tool to achieve the NEO.¹⁶⁷

SP AusNet submitted that given the likely difficulties in aligning expenditure categories across NSPs and NSP specific factors, it is important NSPs are given an opportunity to comment on their

¹⁵⁹ ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013, pp. 1–2; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 15.

¹⁶⁰ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 9.

¹⁵⁸ ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013, pp. 2–3.

¹⁵⁹ ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013; Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 5, p. 3.

¹⁶³ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 4; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 2; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, pp. 12–3.

¹⁶⁴ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 12; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 6–7; Energex, *Energex response to AER's Expenditure forecast assessment guidelines for electricity distribution and transmission - Issues Paper*, 15 March 2013, p. 1; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 9;

¹⁶⁵ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 11.

¹⁶⁶ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 8–9.

¹⁶⁷ PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, p. 6.

performance.¹⁶⁸ It also argued that summing partial performance indicators would derive unrealistically low aggregate benchmarks and it is unclear whether lower level aggregation will lead to more robust benchmarking.¹⁶⁹

We consider that benchmarking can be conducted in a way that either adequately controls for exogenous factors, or is used in reflection of any limitations these factors may imply. We also believe the expected benefits from collecting the proposed data will outweigh the expected collection costs. We carefully considered likely reporting costs in developing expenditure categories and reporting requirements.

We do not believe there is any inconsistency between the use of benchmarking and incentive regulation. While we prefer light handed incentive regulation, benchmarking should create further incentives for NSPs to achieve efficiencies, and importantly, for customers not to be paying for inefficiency. This may be particularly useful when NSPs do not respond to the current regulatory regime's financial incentives.

At a minimum, we intend to use benchmarks to target further assessment. How determinatively we will use the results of benchmarking (or any technique) will depend on the results considered in light of other information.

During consultation we discussed the prospect of developing a "price book" of project cost components for benchmarking transmission capex projects. This was considered relevant given the heterogeneity of such large projects, although the cost of more specific asset components may be more consistent and amenable to comparison. We typically ask our consultants to examine this level of detail in transmission capex assessments, but we see benefit in collecting and assessing this information ourselves. The Australian Energy Market Operator (AEMO) has already begun collating information that might be useful for this purpose. We will continue to liaise with AEMO and the TNSPs regarding the usefulness of this information.

Aggregated category benchmarking

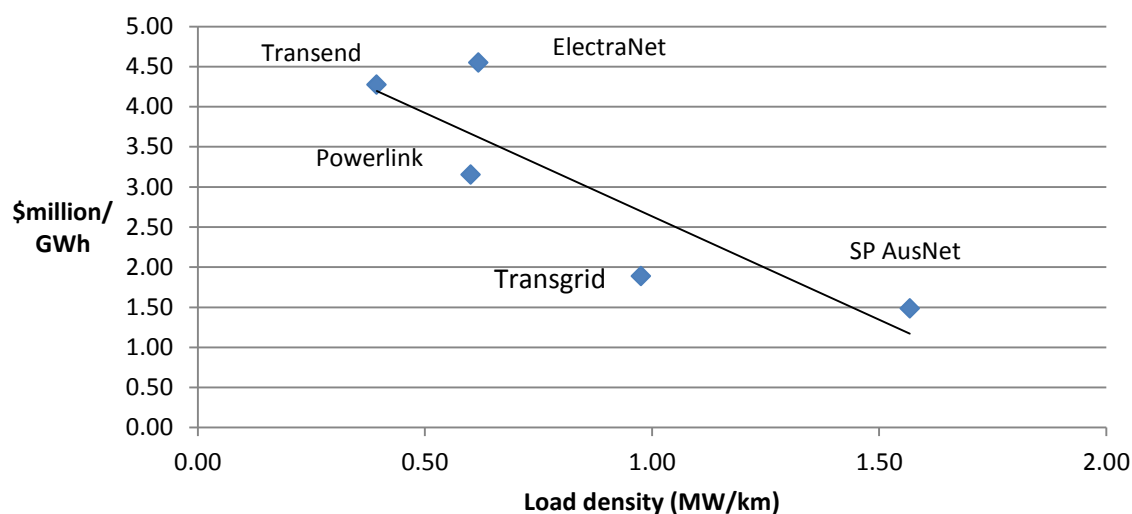
As well as category benchmarks (Attachment B), we will continue to use aggregated category benchmarks such as those presented in recent AER publications. Aggregated category benchmarking captures information such as how much a NSP spends per kilometre of line length or the amount of energy it delivers. Figure 4.1 provides a recent example of such benchmarking used in the issues paper published on the SP AusNet transmission revenue proposal.¹⁷⁰

¹⁶⁸ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 4.

¹⁶⁹ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 12

¹⁷⁰ AER, *Issues Paper- SP AusNet's electricity transmission revenue proposal 2014–15 to 2016–17*, 1 May 2013, p. 31.

Figure 4.1 Opex/electricity transmitted (\$million, nominal)



We intend to improve on these benchmarks by capturing the effects of scale and density on NSP expenditures. A common feature of more detailed benchmarks we propose for DNSPs is categorising expenditures and work volumes according to regional/feeder classifications (that is, central business district, urban, rural short and rural long) many DNSPs already use. We intend to overlay these regional classifications at the total category level. Overall these data are already available and hence impose limited additional burden on DNSPs in terms of data reporting.

Table 4.1 lists expenditures to be used and example scale/ density metrics. We will consult further with stakeholders about these classifications and their use. For example, these types of benchmarks may feature more heavily in annual benchmarking reports in lieu of more detailed benchmarking analysis (which may not be amenable for a summary annual report). We may also consider selectively publishing aggregated benchmarks alongside more detailed measures if they both highlight an issue with a particular activity or type of expenditure.

Table 4.1 Example category expenditure benchmarks

Expenditures	Volume metrics
\$ total capex, opex	Customer numbers/connections
\$ repx, augex, maintenance etc	Line length (km)
\$ repx, augex etc by feeder classifications (CBD, urban, rural short, rural long) ^a	RAB (depreciated and at current replacement cost)
	Customer numbers, energy delivered (GWh) and maximum demand per km of line
	Maximum demand (MW) per customer
	Maximum demand (MW) per km of line
	Network area serviced (km ²)
	Employee numbers

Note: (a) applicable to DNSPs only.

4.4.2 Methodology review

We will assess the methodology the NSP utilises to derive its expenditure forecasts, including assumptions, inputs and models. Similar to the governance framework review (see section 4.4.3), we will assess whether the NSP's methodology is a reasonable basis for developing expenditure forecasts that reasonably reflect the NER criteria.¹⁷¹

We expect NSPs to justify and explain how their forecasting methodology results in a prudent and efficient forecast, so if a methodology (or aspects of it) do not appear reasonable, we will require further justification from the NSP. If we are not satisfied with further justification, we will adjust the methodology such that it is a reasonable basis for developing expenditure forecasts that reasonably reflect the NER criteria.¹⁷² This is similar, for example, to our past assessments of the probabilistic models that some TNSPs used to develop augex forecasts. We assessed the model and generally found it to be reasonable. On the other hand, we did not consider inputs to the model such as the demand forecast or certain economic scenarios to be reasonable in some cases. We therefore made adjustments to those particular inputs to the model.¹⁷³

We consider a good expenditure forecasting methodology should reflect the principles set out in section 4.5 and result in forecast expenditure that is accurate and unbiased.

4.4.3 Governance and policy review

A governance framework includes the processes by which a business goes about making investment and operational decisions to achieve its corporate goals. This involves development of investment plans and their efficient execution in consideration of a firm's key policies and strategies. A good governance framework should:

- identify network requirements
- develop viable options to meet these requirements
- result in a forecast of the expected expenditure to meet these requirements.¹⁷⁴

This should directly lead to a relatively detailed list of network projects and activities that can then be further developed, evaluated and implemented as required. Through each stage of the governance processes there are checks to ensure the chosen investment or activity remains the best choice for the firm to make in the context of current policies and strategies. The governance framework encompasses all facets and levels of decision making including asset management plans and business cases.

We will assess a NSP's governance framework against good industry practice. This will include assessment of asset management plans to determine if they are consistent with incurring efficient and prudent expenditure. The assessment will indicate whether the strategies, policies and procedures employed by the NSP would produce forecasts that reflect the expenditure criteria.¹⁷⁵ The assessment will also inform our detailed reviews, including identifying areas for detailed review, as well as the

¹⁷¹ NER, clauses 6.5.7(c) and 6A.6.7(c).

¹⁷² NER, clauses 6.5.7(c) and 6A.6.7(c).

¹⁷³ For example, see AER, *Draft decision: Powerlink transmission determination 2012-13 to 2016-17*, November 2011, pp. 107–17.

¹⁷⁴ British Standards Institution, *Publicly Available Specification 55*, 2008 (PAS 55).

¹⁷⁵ NER, clauses 6.5.7(c) and 6A.6.7(c).

derivation of alternative forecasts if necessary (similar to past distribution and transmission determinations).¹⁷⁶

We can use documents such as the Publicly Available Specification PAS 55:2008 and the International Infrastructure Management Manual for guidance and criteria on good industry practice.¹⁷⁷

Where a NSP's governance framework is consistent with good industry practice, we will assess whether the NSP's capex forecasts replicate the outcomes of good governance. This includes assessing, in our detailed project reviews, whether the NSP appropriately utilised its capital governance framework when developing its capital program. If so, this may support an assessment that the NSP's capex forecast reasonably reflects the capex criteria. However, findings of good governance will not be in any way determinative that expenditure forecasts are efficient and prudent. We expect a NSP to explain any departures from the framework.

Where a NSP's governance framework is not consistent with good industry practice, we will note which aspects of the framework the NSP can improve in future regulatory control periods. We may also use findings in relation to the governance framework to better target detailed project reviews on potential areas of concern. The more significant a framework's shortcomings, the less confidence we would have that the NSP can rely on the framework to produce a capex forecast that meets the NER criteria.¹⁷⁸

While not generally examined in detail, we may also assess the governance framework as it applies to opex decisions.

The ENA submitted that our past governance and policy reviews appear to have had little influence on past final decisions. It proposed that these reviews could reduce regulatory costs and warrant greater use. However, they consider that for this outcome to be achieved the reviews should be applied consistently and where comfort is taken from these reviews consequentially less scrutiny should be applied on at least parts of the proposed expenditure. They consider that to the extent governance reviews are not determinative and don't influence the level of scrutiny, there is little benefit from the reviews.¹⁷⁹

Ergon Energy also submitted that, to the extent such reviews are to be relied on in the future, there would need to be sufficient confidence in the processes to be applied.¹⁸⁰

We generally agree that governance and policy reviews should be consistently applied. We consider this creates certainty and should reduce regulatory costs. However, the detail and effort appropriate to any given review will depend on the particular circumstances.

While we consider that having good corporate governance is likely necessary to achieve efficient capex, having good governance is not conclusive of efficient expenditure or that forecast expenditure

¹⁷⁶ For example, see AER, *Draft decision: Aurora Energy Pty Ltd distribution determination 2012–13 to 2016–17*, November 2011, p. 114.

¹⁷⁷ Our consultants have referenced these documents in past determinations, for example: EMCa, *ElectraNet revenue determination: Technical review: Advice on forecast capital and operating expenditure, contingent projects and performance scheme parameters: Public (redacted) version*, 30 October 2012, p. 44; Nuttall Consulting, *Report – Capital expenditure: Victorian electricity distribution revenue review*, 4 June 2010, p. 41.

¹⁷⁸ NER, clauses 6.5.7(c) and 6A.6.7(c).

¹⁷⁹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 12.

¹⁸⁰ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 9.

is efficient. Therefore, while we agree with the ENA's general proposition that the findings from governance reviews should be used to lessen other review and associated regulatory burden where possible, we do not believe governance reviews need to be entirely determinative for them to have positive value. In addition, while good governance plans may exist, without a detailed technical review of sample projects it would be difficult to determine if these plans are being applied effectively.

4.4.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works.

We acknowledge that modelling will generally be a simplification of reality and will have inherent limitations as a result. We will consider any limitations in the modelling when using the results of modelling in our assessment.

More detail on predictive modelling and submissions on its use are considered in Attachment B which covers the modelling of replacement and augmentation capex.

4.4.5 Trend analysis

We will compare a NSP's forecast expenditure and work volumes to its historical levels. In this knowledge, we will expect NSP's to explain where its forecast expenditures and volumes are materially different to recent history. In the absence of such explanation, we may conclude the NSP's forecast expenditure is not efficient and prudent. In such a case, we may consider historical expenditure in determining the best estimate of forecast expenditure.

We consider trend analysis provides a reasonably good technique for estimating future expenditure requirements where historical expenditure has similar drivers to future expenditure and these drivers can be forecast.

The ENA submitted that trend analysis is useful for expenditure categories that exhibit relatively consistent levels of expenditure over time. However, they submitted that we should take into account circumstances that have changed over time which result in a changed expenditure profile if the NSP can demonstrate such change.¹⁸¹

We agree that trend analysis is most useful for relatively consistent expenditure. For this reason, it is likely to be most applicable to opex and to relatively recurrent capex. We also agree that NSP's circumstances may change over time. However, whether or not changes in forecast expenditure are required as a result of changed circumstances will depend on the overall circumstances of the NSP in question. In particular, one relevant consideration is whether a change in expenditure is necessary for the total expenditure forecast to reasonably reflect the expenditure criteria.

4.4.6 Cost–benefit analysis

Cost–benefit analysis is critical to best practice decision making. While the level of analysis may vary with the value of the expenditure, firms in competitive markets will normally only undertake investments they consider will create wealth for their shareholders. This requires the investments be net benefit positive. With the exception of expenditure to meet binding legal obligations, we consider

¹⁸¹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 9.

economic justification for expenditure by a monopoly network business also requires positive expected net benefits demonstrated via cost benefit analysis.

All expenditure also needs to be prudent. To show efficiency we consider cost benefit analysis will normally be required to show the option chosen has the highest net benefit.¹⁸² To demonstrate prudence, firms will need to show the decision reflects the best course of action, considering available alternatives. Generally, the project with the highest net benefit will have the lowest life cycle costs when compared to other projects on an equivalent basis. We consider this is consistent with achieving the lowest sustainable cost to achieve the network supply and reliability outcomes sought.

If options analysed have different characteristics, NSPs should show via cost benefit analysis that the option chosen is efficient relative to other options. For example, a cost benefit analysis could show a higher cost option is efficient over its life cycle due to a longer life, due to lower operating costs, or due to higher reliability. This means options must be directly comparable (for example via making lives comparable and comparing net benefits in present value terms) and all material incremental cost and benefits of different options should be accounted for.

The ENA submitted that we should focus on dynamic efficiency in promoting the NEL objective.¹⁸³ We consider that an increased focus on cost benefit analysis is consistent with all facets of efficiency. Importantly, we consider that this will promote dynamic efficiency as efficient changes in production processes through time should be cost benefit positive.

In the absence of adequate economic justification and demonstration of the efficiency and prudence of the option selected, we are unlikely to determine forecast expenditure is efficient and prudent.

4.4.7 Detailed project review (including engineering review)

We are likely to continue to perform detailed reviews of a sample of projects from different expenditure categories to inform our assessment of expenditure forecasts in those categories, with the assistance of technical consultants.

The detailed reviews will assess whether the NSP used processes that would derive efficient design, costs and timing for each project. This includes assessing whether the NSP followed good governance in developing each project and the business cases, cost-benefit analysis and other economic justification for the proposed project. If we find any sources of inefficiency, we will make the necessary adjustment(s) so the project costs reflect efficient costs. The detailed reviews will likely assess:

- the options the NSP investigated to address the economic requirement. For example, for augmentation projects:
 - the extent to which the NSP considered and provided for efficient and prudent non-network alternatives¹⁸⁴
 - net present value analysis including scenario and options analysis

¹⁸² This is consistent with showing the expenditure results in the lowest sustainable cost. Where the investment cost outweighs the benefits, the cost benefit analysis should show the chosen option is the least negative from net benefit perspective.

¹⁸³ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 5.

¹⁸⁴ NER, clauses 6.5.7(c)(10) and 6A.6.7(c)(12).

- regulatory investment tests for transmission (RIT-Ts) and regulatory investment tests for distribution (RIT-Ds), if available
- whether the timing of the project is efficient
- unit costs and volumes, including comparisons with relevant benchmarks (see Attachment B)
- whether the project should more appropriately be included as a contingent project¹⁸⁵
- deliverability of the project, given other capex and opex works
- the extent to which the NSP consulted with electricity consumers and how the NSP incorporated the concerns of electricity consumers in developing the project.¹⁸⁶ This is most relevant to core network expenditure (augex and repex) and may include the NSP's consideration of the value of customer reliability (VCR) standard or a similar appropriate standard.

Technical experts will usually help us conduct these assessments by providing detailed engineering advice. Most stakeholders supported us obtaining technical advice.¹⁸⁷ The ENA submitted that engineering advice would be essential to support the use of other assessment techniques. The ENA and SA Power Networks suggested they be used to assess large material projects that may not be captured in benchmarking or modelling analysis.¹⁸⁸ The ENA noted that engineering assessments must be rigorous, fully justified and properly substantiated.¹⁸⁹

Grid Australia agreed that assessment techniques (such as robust engineering assessment) were effective in the past and should continue to be the primary tool assessing transmission revenue determinations.¹⁹⁰ Ergon Energy indicated engineering review can provide detailed and accurate assessments, although it can be subjective, costly, intrusive, time consuming and is only useful for reviewing one business at a time.¹⁹¹ Ergon Energy and SA Power Networks submitted engineering assessments should be used to assess material projects that may not be captured via other techniques.¹⁹²

We agree detailed project review (including engineering review) will often be critical to assess expenditure forecasts. We also agree that assessments should be rigorous, fully justified and properly substantiated. However, the level of rigour and justification of techniques will often be proportionate to the value of the technique's output to the assessment process. In line with stakeholder comments, we

¹⁸⁵ This principally relates to augex. See NER, clauses 6.5.7(c)(9A) and 6A.6.7(c)(10).

¹⁸⁶ NER, clauses 6.5.7(c)(5A) and 6A.6.7(c)(5A).

¹⁸⁷ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 12; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 3; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 9; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A - Expenditure forecast assessment guideline*, 15 March 2013, p. 5.

¹⁸⁸ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 12; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A - Expenditure forecast assessment guideline*, 15 March 2013, p. 5.

¹⁸⁹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 12.

¹⁹⁰ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 3.

¹⁹¹ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 9.

¹⁹² CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A - Expenditure forecast assessment guideline*, 15 March 2013, p. 5; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 9.

intend to target detailed project and engineering reviews and use these when other assessment techniques may be lacking.

4.5 Assessment principles

We have a number of assessment techniques available to us, including some we have not used before. Our assessment techniques may complement each other in terms of the information they provide, so we can use them in combination when forming a view on expenditure proposals. Accordingly, we have a holistic approach to using our assessment techniques.

This means we intend to give ourselves the ability to use all of our techniques when we assess expenditure, and to refine them over time. Depending on the assessment technique, we may be able to use it to assess expenditure in different ways—some that may be more robust than others. For example, while we intend to use economic benchmarking techniques, it may not be appropriate to use a data intensive benchmarking technique such as stochastic frontier analysis (SFA) until we can obtain robust data. However, this does not mean it will never be appropriate to use SFA.

To determine which techniques to use when we assess expenditure, we may consider the assessment principles outlined in section 4.5.1. These principles also apply equally when assessing the appropriateness of NSPs' forecasting techniques. We have not, however, incorporated the principles into the Guidelines because we consider this is unnecessarily prescriptive. Our position on assessment principles is a departure from our issues paper, which suggested we would select techniques to include in the Guidelines and potentially apply at the F&A stage.¹⁹³

We consider our approach is consistent with the AEMC's final rule change determination, which confirmed the NER allow us to assess a NSP's proposal using any techniques we consider appropriate.¹⁹⁴ Importantly, the NER do not confine us to assessing expenditure using the approach a NSP takes in its proposal.¹⁹⁵ Accordingly, the Guidelines do not exclude any of the techniques we used in the past, nor do they preclude us from implementing more techniques over time.¹⁹⁶

Once we receive a NSP's expenditure forecasting approach (at the F&A stage) we will be in a better position to know which techniques we will likely use to assess the NSP's proposal, but we will not exactly how we will assess a proposal until we see it.

We received several submissions from stakeholders on principles for selecting techniques. Some submissions generally supported the principles outlined in our issues paper, but considered we could make some improvements.¹⁹⁷ Some submissions suggested that we should frame our assessment

¹⁹³ AER, *Expenditure forecast assessment guidelines Issues paper*, pp. 17, 24.

¹⁹⁴ AEMC, *Rule determination*, 29 November 2012, p. 109.

¹⁹⁵ AEMC, *Rule determination*, 29 November 2012, p. 112.

¹⁹⁶ This approach is endorsed by the MEU. Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 13–4.

¹⁹⁷ For example, Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 7–8, 13–4; EA Technology Australia, *Expenditure forecast assessment guidelines for electricity distribution and transmission issues paper*, 14 March 2013, pp. 1–2; ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013, p. 2; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, pp. 9–11; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 7–10; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A - Expenditure forecast assessment guideline*, 15 March 2013, pp. 4–5; Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 5; PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, pp. 9–10.

principles in the long term interests of consumers.¹⁹⁸ Others argued our distinction between assessing expenditure and assessing efficiency is unnecessary.¹⁹⁹ Some submissions stated that principles should ensure we do not select techniques that place significant cost or administrative burden on NSPs to gather data.²⁰⁰ However, other submissions sought greater clarity from the Guidelines.²⁰¹

We agree it is unnecessary to distinguish between assessing expenditure and assessing efficiency. As chapter 3 explains, the NEO and the expenditure criteria ensure that efficiency is necessarily an integral component of assessing expenditure. However, it follows that we do not need to explicitly frame principles in the context of the NEO either. The NEL already ensures we perform our economic regulatory functions (including assessing expenditure) in a manner that will, or is likely to, contribute to achieving the NEO.

In terms of the cost of gathering data, we do not aim to impose unreasonable cost or administrative burdens on NSPs. However, we will collect new information to enable us to assess expenditure using the techniques we consider appropriate. We consulted on and carefully considered the additional cost and burden of this new information (which is ultimately borne by consumers) and balanced this against the significant expected improvements in the robustness of our assessments. In particular, regularly reporting on the relative efficiency of NSPs will assist network users in engaging more effectively in the process of setting efficient expenditure allowances in transmission and distribution determinations. The public scrutiny of NSPs and their performance is likely to encourage them to achieve further improvements, as well as identify areas we are likely to target at the time of their next price review.

We do not agree with the ENA's submission that the Guidelines should explain when and how we will use assessment techniques so NSPs can target their proposals towards meeting relevant regulatory tests in light of our approach.²⁰² We consider this approach is unnecessarily prescriptive and

¹⁹⁸ For example, Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 7; EA Technology Australia, *Expenditure forecast assessment guidelines for electricity distribution and transmission issues paper*, 14 March 2013, pp. 1–2; PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, pp. 9–10.

¹⁹⁹ For example, SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, pp. 9–11; PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, pp. 9–10.

²⁰⁰ For example, Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 11; ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013, p. 2; VIC DNSPs Cover letter to Submission, *AER Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. iii; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, pp. 9–11.

²⁰¹ For example, Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, pp. 1, 11. Endorsed by Ausgrid, Endeavour Energy and Essential Energy, *NSW DNSP submission on Forecast Expenditure Assessment Guideline -Issues Paper*, 14 March 2013, p. 2; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 4, Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, pp.1–2, VIC DNSPs Attachment to submission, *Submission to the AER, Expenditure forecast assessment guidelines for electricity distribution and transmission, March 2013*, pp. 1–2, SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 1, CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 1, Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 1, United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator*, 19 March 2013, pp. 5–6.

²⁰² Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, pp. 1–2, 11; Endorsed by Ausgrid, Endeavour Energy and Essential Energy, *NSW DNSP submission on Forecast Expenditure Assessment Guideline -Issues Paper*, 14 March 2013, p. 2; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 4, Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, pp. 1–2; VIC DNSPs Attachment to submission, *Submission to the AER, Expenditure forecast assessment guidelines for electricity distribution and transmission, March 2013*, pp. 1–2; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 1; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper*

inconsistent with the AEMC's intent. The intent of the changes to the NER was not to codify exactly when, how and why we will use expenditure assessment techniques. Rather, the AEMC was quite clear that the Guidelines are not intended to limit the AER.²⁰³

The intention of this final rule is to facilitate early engagement on a NSP's expenditure forecast methodology and ensure that both the AER and NSPs are aware, in advance, of the information the AER requires to appropriately assess a NSP's proposal. It is intended to bring forward and potentially streamline the regulation information notice stage(s) that currently occur, as well as to expedite the AER's understanding of the NSP's approach to expenditure forecasting. It does not restrict the AER's ability to use additional assessment techniques if it considers these are appropriate after reviewing a NSP's proposal.

We understand that NSPs desire certainty in how we will assess their proposals. Inherent in assessing expenditure and setting efficient capex and opex allowances is a need for us to be satisfied that the assessment techniques we use are appropriate. Equally, we must be satisfied that the forecasting techniques NSPs use are appropriate. Ultimately, what we consider is appropriate is a matter for our discretion and judgement.²⁰⁴

However, we need the flexibility to respond to issues stakeholders may raise during determination processes, and to refine our techniques over time. We consider our Guidelines strike the appropriate balance between flexibility and certainty by explaining our approach to assessing expenditure in light of the requirements of the NEL and NER. Accordingly we consider it unnecessary to prescribe in the Guidelines, any principles to follow when deciding to select or to weight certain techniques.²⁰⁵

However, to provide some guidance for NSPs, we consider there is merit in outlining some best regulatory practice principles we might consider when assessing expenditure. If we need to decide the appropriateness of a technique (whether it be our assessment technique, the NSP's forecasting technique, or both) we would typically have regard to them. This does not mean we intend to set out a detailed consideration of every principle whenever we choose a technique to assess expenditure—every principle may not always be relevant. Nor do we intend to enter into debate about whether or not certain techniques appropriately comply with the principles. However, as a public decision maker, we have an overarching obligation to base our decisions on sound reasoning.²⁰⁶ This ensures we will explain how and why we accept or do not accept an expenditure proposal.

4.5.1 Proposed principles

Some of the principles we outline here are different to those set out in our issues paper. We consider they generally reflect the tenor of most submissions we received on this issue. The principles below are broadly similar to the PC's evaluation criteria for benchmark measures outlined in its report on Electricity Network Regulatory Frameworks. The PC report discusses evaluation criteria in the context of benchmarking,²⁰⁷ but we consider they are applicable to all assessment techniques.

Validity

Overall, we consider a technique must be valid, otherwise it is not useful. That is, it must be appropriate for what we need it to assess. In our case, this is typically efficiency (or inefficiency).

Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, 15 March 2013, p. 1; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 1; and United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper*, Australian Energy Regulator, 19 March 2013, pp. 5–6.

²⁰³ AEMC, *Rule determination*, 29 November 2012, p. 114.

²⁰⁴ AEMC, *Rule determination*, 29 November 2012, p. 113.

²⁰⁵ For example, Grid Australia, *Working Draft Expenditure Forecast Assessment Guidelines (Electricity Transmission)*, 11 June 2013, p. 18.

²⁰⁶ AEMC, *Rule determination*, 29 November 2012, p. 112.

²⁰⁷ Productivity Commission, *Electricity Network Regulatory Frameworks – Final Report*, Volume 1, 9 April 2013, pp. 163–81.

The PC suggests that valid techniques should account for time, adequately account for factors outside the control of NSPs and (where possible) use reliable data.²⁰⁸ Generally, we will not be in a position to satisfy ourselves whether a technique is appropriate until after we receive data or information to test it.

Accuracy and reliability

We consider a technique is accurate when it produces unbiased results and is reliable when it produces consistent results. In our view, objective techniques (such as a benchmark based on actual data) are inherently more accurate than subjective techniques (such as engineering review); they are less susceptible to bias and therefore others can judge them fairly. Reliable techniques should produce similar results under consistent conditions. In some cases, techniques may require testing and calibration for us to be satisfied of their accuracy and reliability.

Robustness

Robust techniques remain valid under different assumptions, parameters and initial conditions. However, we also consider robust techniques must be complete. A technique that is lacking in some material respect cannot be robust.

Transparency

A technique that we or stakeholders are unable to test (sometimes referred to as a 'black box') is not transparent because it is not possible to assess the results in the context of the underlying assumptions, parameters and conditions. In our view, the more transparent a technique, the less susceptible it is to manipulation or gaming. Accordingly, we take an unfavourable view of forecasting approaches that are not transparent.

Parsimony

Multiple techniques may be able to provide the same information, but to varying degrees of accuracy and with varying degrees of complexity. We will typically prefer a simpler technique (or one with fewer free parameters) over more complex techniques, if they measure equally against other selection principles. Where possible, we intend to move away from assessment techniques that draw us and stakeholders into unnecessary detail when there are alternative techniques. We reiterate that our role is to assess total capex and opex forecasts. The NER do not require us to assess individual projects.²⁰⁹

Fitness for purpose

We agree with the PC that it is important to use the appropriate technique for the task.²¹⁰ As explained in our issues paper, no technique that we or NSPs rely on can produce a perfect forecast.²¹¹ However, the NER does not require us to produce precise estimates.²¹² Rather, we must be satisfied that a NSP's forecast (or our substitute forecast) reasonably reflects the expenditure criteria. Accordingly, we will consider fitness for purpose in this context.

²⁰⁸ Productivity Commission, *Electricity Network Regulatory Frameworks – Final Report*, Volume 1, 9 April 2013, pp. 163–81.

²⁰⁹ AEMC, *Rule determination*, 29 November 2012, p. 113.

²¹⁰ Productivity Commission, *Electricity Network Regulatory Frameworks – Final Report*, Volume 1, 9 April 2013, p. 181.

²¹¹ AER, *Guidelines issues paper*, December 2012, p. 22.

²¹² AEMC, *Rule determination*, 29 November 2012, p. 112.

5 Consideration of incentive frameworks

This chapter considers the interaction between incentive frameworks and our approaches to assessing capex and opex forecasts.

We apply three incentive schemes: the EBSS, the STPIS and the demand management incentive scheme (DMIS).²¹³ In consultation with industry, we are developing a CESS and reviewing the EBSS.

Our expected approach to assessing expenditure forecasts for the next regulatory period will affect incentives in the current period. Our default approach for opex is to rely on revealed costs which requires a particular incentive design when forecasting NSPs' expenditures. However, we may choose to depart from this approach and use information other than a NSP's historical expenditure to assess and set forecast allowances. This section considers when we may depart from the revealed cost approach and should be read in conjunction with section 4.2.

For capex, our approach to ex post reviews may overlap with our assessment of expenditure forecasts. That is, in our ex-post review of capex, some of the results of expenditure forecast assessment techniques may be considered. Particularly, the results of benchmarking and the review of governance procedures may be of particular relevance.

While issues of demand management and service performance outcomes affect our expenditure forecast assessment, our assessment approach does not materially affect the incentives in the STPIS and DMIS.

This chapter should be read alongside the explanatory statements for the revised EBSS and draft CESS guidelines which more thoroughly examine the application of incentives.

5.1 Overview of incentive arrangements

Operating expenditure objectives

The EBSS shares opex efficiency gains and losses between NSPs and network users. The specific design of the EBSS addresses two issues:

- (1) If we set forecast opex allowances with reference to revealed costs in a specific year, the NSP has an incentive to increase its expenditure in that year so as to increase its opex allowance in the following regulatory control period.
- (2) Similarly, if we apply a revealed cost forecast, a NSP that is able to reduce (recurrent) expenditure near the beginning of the regulatory control period can retain the benefits of that reduction longer than if it were to reduce expenditure closer to the end of the period. Consequently, incentives weaken over the period.

²¹³ Under clause 6.6.3 of the NER we have the ability to publish a demand management and embedded generation connection incentive scheme (DEMEGCIS). Though we have not published a NEM wide DMEGCIS, under a previous version of the NER, we have prepared consistent demand management incentive schemes for each jurisdiction. We also intend to commence informal engagement on matters relevant to the form of a new demand management incentive scheme based on the recommendations set out in the Australian Energy Market Commission's Final Report on its Power of Choice review. This informal engagement is likely to take place in parallel with the AEMC's DMEGCIS rule change process.

The EBSS allows a NSP to retain the benefits of an efficiency gain for five years, irrespective of the year of the regulatory control period in which the NSP made the efficiency gain. The NSP thus faces a constant incentive to pursue efficiency gains over a regulatory control period.

The current EBSS²¹⁴ relies on a base-step-trend forecasting approach, using a revealed cost base year (Box 2).

Box 2 Revealed costs, exogenous forecasts and the base-step-trend forecasting approach

A revealed cost forecasting approach relies on the historical costs (revealed costs) of the NSP. Where incentives are effective, a NSP's actual expenditures should "reveal" its efficient costs. We do not, however, automatically assume that incentives have been effective—we test this before relying on revealed costs. Revealed costs may mitigate the problem of information asymmetry faced by regulators of natural monopolies. An alternative method is to use exogenous forecasts, which could be based on the benchmark costs of another NSP, or on the estimated costs of undertaking activities. However, NSPs cannot influence exogenous forecasts through their actual performance, thus using these forecasts may have different incentive effects.

We commonly use the 'base-step-trend' approach to assess and determine forecast opex. Using a revealed cost approach, we use a 'base year' of expenditure as the basis for the forecast. We then adjust it to account for changes in circumstances between the base year and the forecast period. We review make any adjustments required to base opex to ensure it reflects prudent and efficient costs. This is particularly necessary if an EBSS was not in place in the current regulatory control period. We then trend forward base opex by accounting for forecast changes to input costs, output growth and productivity improvements in the forecast period. Finally, we add any other efficient costs not reflected in base opex (referred to as step changes).

Typically, we use the revealed costs of the second or third last year in a regulatory control period as the base year. The second last year is the most recent available data at the time of the determination, so likely to best reflect the forecast period. Sometimes, we use the third last year, being the most recent year of available data when the NSP submitted its regulatory

If the NSP does not expect its revealed costs to be used to set forecast allowances, the incentive properties of the existing EBSS will be affected. If we apply a pure exogenous forecast, there is no link between a NSP's actual expenditure and its forecasts, so the incentive to inflate base year expenditures (explained above) does not exist. Further, a NSP will retain all the benefits of reducing its expenditure since its allowance in the following period will be the same regardless.

During consultation on the Guidelines, we noted concerns that NSPs may not respond to the revealed cost incentive framework, and thus there is a need to assess the efficiency of base year expenditures. Stakeholders requested we clarify when and how we would move away from the revealed cost

²¹⁴ AER, *Electricity distribution network service providers efficiency benefit sharing scheme*, Version 1, June 2008; AER, *Final Electricity transmission network service providers efficiency benefit sharing scheme*, Version 1, September 2007.

forecasting approach for opex.²¹⁵ A number of NSPs requested we outline where we may not use the revealed cost base-step-trend forecasting approach.²¹⁶

Capital expenditure incentives

We must make an ex post review of the prudence and efficiency of actual/historical capex²¹⁷ and some of our techniques for undertaking an ex post review may be common to our ex ante assessment of capex forecasts.

The CESS will share the rewards/penalties of underspends/overspends of forecast allowances between NSPs and their customers. Our proposed forecasting approach for capex does not rely on a particular method, including any pre-commitment to use base year expenditures. In this way, the CESS (and all capex incentives) is not dependent on our forecasting approach in the same way as opex.

Service performance and demand management incentives

The STPIS provides an incentive for a NSP to maintain and improve the reliability of network services. The DMIS provides incentives for DNSPs to implement efficient non-network alternatives, or to manage the expected demand for standard control services.

5.2 Proposed approach

Operating expenditure

Our expected opex forecasting assessment approach will affect NSPs' incentives to pursue efficiency gains. It is therefore appropriate to outline how we will forecast opex in advance of our determinations.

We prefer to continue using a revealed cost base-step-trend forecast, in tandem with the current EBSS. We can thus perform a non-intrusive assessment of and determination on opex allowances. Our approach relies on the incentive framework to encourage NSPs to achieve continual efficiency gains. Further, it is appropriate for forecasting opex, given its recurrent nature.

In some instances, the revealed cost approach is not appropriate because historical expenditures are inefficient and thus revealed costs cannot be expected to form a basis for efficient forecasts. Specifically, the revealed cost approach may not be appropriate when a NSP appears materially inefficient compared to its peers and, in tandem with the application of incentive schemes, the revealed cost forecast would yield an outcome that is inconsistent with the opex criteria, taking into account the opex factors.²¹⁸

For this reason we will scrutinise the efficiency of proposed base year expenditures. If we identify the above concerns, we will consider adjusting that base year. We will combine the accepted base year with our step-trend approach to set a forecast opex allowance for the regulatory control period.

²¹⁵ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p.15, Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 6.

²¹⁶ APA group, Submission to AER expenditure incentive guideline issues paper, May 2013, p. 4.
CitiPower, Powercor, SA Power Networks, *Response to the expenditure incentives guideline for electricity networks service providers– issues paper*, 10 May 2013, p. 13.

²¹⁷ NER clauses S6.2.2 and SA6.2.2

²¹⁸ NER clauses 6.5.6(c) and 6A.6.6(c)

Base year adjustments

We will make base year adjustments where:

- a NSP is materially inefficient compared to its peers, and
- in tandem with the application of incentive schemes, the revealed cost forecast would yield an outcome that is inconsistent with the opex criteria.

In deciding whether a NSP appears materially inefficient, we will consider:

- the results of our expenditure review techniques, including economic benchmarking, category analysis and detailed engineering review
- the NSP's proposal and stakeholder submissions.

If material inefficiencies are unexplained after we review the NSP's proposal and consideration of submissions, we will consider whether the outcome of applying the proposed base year in conjunction with incentive schemes would result in efficient outcomes. This consideration would depend on the size of the identified inefficiency and the value of scheme penalties or rewards.

If we make an adjustment, it would likely be only to the extent required to address the material inefficiency. We will then subject the accepted or adjusted base year expenditures to any step changes and trend adjustments as per the Guidelines.

Alternative forecasting methods

We are unlikely to make exceptions in the application of the revealed cost forecasting approach where a NSP appears to be relatively efficient and responding to incentives. This includes situations where NSPs suggest historical costs in base years are lower than efficient costs.

Capital expenditure

Our capex forecast assessment approach may overlap the ex post review of capex. For example, we may use an engineering review of projects/programs and a review of governance procedures, for both ex post and ex ante capex assessments. Further, we may apply benchmarking to review the efficiency of historical expenditure decisions. In ex post reviews, however, we must account for only information and analysis that the NSP could reasonably be expected to have considered or undertaken when it spent the relevant capex. For this reason, some differences may arise between our capex forecast assessment approach and our ex post expenditure review.

5.3 Justification for our opex approach

5.3.1 General approach and incentive considerations

Under the NER we must accept or not accept a NSP's opex forecast.²¹⁹ This choice is governed by whether we consider the proposed forecast reasonably reflects the opex criteria. If we do not accept the forecast, we must estimate the required expenditure that reasonably reflects the opex criteria. The criteria provide that the forecast must reasonably reflect the efficient costs that a prudent operator would require to meet expenditure objectives given a realistic forecast of demand and cost inputs.²²⁰

²¹⁹ NER clauses 6.12.1.(4)(i) and 6A.14.1.(3)(i).

²²⁰ NER clauses 6.5.6(c) and 6A.6.6(c).

In assessing forecast opex, we must have regard to whether the opex forecast is consistent with any opex incentive scheme.²²¹ If the base year opex reflects inefficient costs, then continuing with a revealed cost approach may not result in a prudent, efficient forecast of costs consistent with the opex criteria.

In particular, if an opex forecast plus any EBSS increment/decrement is more than efficient costs plus the NSP's share of efficiency gains or losses, then we are justified in moving away from the revealed cost forecasting approach. In such a case, the level of historical costs plus any carryover would not lead to an efficient forecast. This situation may arise because a NSP does not respond to incentives or appropriate incentives were not in place for efficient expenditure decisions.

Where a NSP does not respond to incentives the sharing of rewards or penalties would not be in the long term interests of consumers. This problem is compounded when the initial forecast was inaccurate (due to error or changing circumstances). Where a NSP responds to incentives, it will make efficient expenditure decisions regardless of the forecast. These efficient (historic) expenditures can then be used as the basis for opex forecasts. However, where a NSP does not respond to incentives, the inaccuracy in the initial forecast may be perpetuated in carryover amounts, as well as in the NSP's expenditures not moving towards their efficient level.

Where there were not appropriate incentives in place, then the use of revealed costs may also be inappropriate. Without appropriately balanced incentives, historical opex may not necessarily be efficient. This may be because of poor incentives to maintain service quality or alternatively expenditures may be too high as historical expenditures are taken to influence forecast expenditures.

Where there is an EBSS in place and a NSP is appropriately responding to incentives we prefer the application of a revealed cost forecasting approach. Opex is largely recurrent, so historical costs provide an indication of forecast requirements. Where there is an EBSS in place, there is a constant incentive across a regulatory period for a NSP to pursue efficiency gains. Hence, when there is an EBSS in place and a NSP appropriately responds to incentives, revealed costs provide a good indication that forecasts will be efficient.

However, we will not assume that a NSP is appropriately responding to incentives simply because an EBSS is in place. We must test the NSP's efficiency before relying on its revealed costs. As we explain below, we will likely use a number of techniques to assess the efficiency of a NSP's base year, including economic benchmarking techniques.

Alternative forecasts

Under the revealed cost approach, an incentive exists for NSPs to apply alternative forecasting approaches, such as a "bottom up" forecast of all or part of opex, or claiming that historical opex costs do not reflect forecast requirements. By doing so, NSPs can exploit their information advantage and gain returns in excess of a fair sharing of efficiency gains.

We are unlikely to accept alternative forecasts where NSPs are responding to incentives because:

- the revealed cost approach is unbiased, non-intrusive and well accepted
- deviation from this approach may incentivise inefficient behaviour and prevent consumers from receiving a fair share of efficiency gains.

²²¹ NER clauses 6.5.6(e)(8) and 6A.6.6(e)(8).

Inefficient low historical costs and the EBSS

NSPs may claim that opex forecasts should not be based upon historical costs because base year costs are lower than their efficient costs. We are unlikely to accept these suggestions where an EBSS is in place. If a NSP assumes an exogenous approach is used to set forecasts in the following period, and an EBSS is in place, they will have a strong incentive to reduce expenditure. This will maximise the reward they receive through the EBSS. If the revealed cost approach is not used to forecast expenditure they will not only retain all efficiency gains, they will also receive a further reward through the EBSS. Thus they will retain more than 100 per cent of the efficiency gain and consumers will be worse off as a result of the non-recurrent efficiency gain. This is not in the long term interests of consumers.

In such situations, it is appropriate to retain the revealed cost forecasting approach. Although the opex forecast will be lower than the efficient level, the NSP will be rewarded as if the non-recurrent efficiency gain was recurrent. In net present value terms this means that the NSP would be better off from making the efficiency gain, even with the lower opex forecast, due to the EBSS carryover. Regardless of whether the efficiency gain is recurrent or not, a revealed cost forecasting approach plus the EBSS carryover, in net terms, will provide the NSP its efficient costs plus its share of efficiency gains or losses.

5.3.2 Approach to reviewing base year expenditures

Our proposed approach aligns with the MEU's submission that the first step to achieving the benefit of an EBSS in a regulatory process is to ensure that the opex allowances are initially close to the frontier.²²²

A number of submissions commented on the complexity of determining whether a NSP is responding to incentives. They noted that simply observing trends of NSPs overspending their opex allowances may not be adequate—that is, this behaviour does not necessarily suggest inefficiency or imply a lack of response to incentives.²²³ Further, expenditures may differ from forecasts for a number of reasons.²²⁴ Grid Australia forwarded considerations that may be relevant to determining whether a NSP is responding to incentives.²²⁵

We acknowledge that there are a number of considerations that may be relevant to determining whether a NSP is responding to incentives. We anticipate using different techniques to form a view on the consistency of base opex with the expenditure criteria, and on any appropriate adjustment. We will not accept on face value that overspends or underspends are inefficient.

The APA Group suggested we consider total expenditure in deciding whether a NSP has responded to incentives.²²⁶ In deciding whether a NSP has responded to incentives we will consider all relevant assessment techniques including economic benchmarking, which examines total costs. The APA Group also urged us to reconsider applying productivity adjustments in addition to the operation of incentive schemes. They stated that the application of a productivity adjustment in addition to an incentive scheme will disproportionately disadvantage the most efficient businesses and make it far more likely that efficient firms will face penalties under the scheme.²²⁷

²²² Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 22.

²²³ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 5.

²²⁴ ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013, p. 2.

²²⁵ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p. 10.

²²⁶ APA group, *Submission to AER expenditure incentive guideline issues paper*, May 2013, p.6.

²²⁷ APA group, *Submission to AER expenditure incentive guideline issues paper*, May 2013, p.5.

As stated in section 4.2, we must determine opex forecasts that reasonably reflect the efficient costs that a prudent operator would require to meet the expenditure objectives given a realistic forecast of demand and cost inputs.²²⁸ The efficient costs will include any expected efficiency gains. Expected efficiency gains can be decomposed into shifts in the efficiency frontier and any changes in the distance to the frontier. When a NSP is a significant distance from the efficiency frontier we will address this through a base year adjustment. The forecast productivity change then reflects only the forecast shift in the efficiency frontier. This will ensure that NSPs are not disproportionately penalised under the scheme.

JEN submitted that we may place undue weight on economic benchmarking to inform a move from revealed costs to an exogenous forecasting approach prematurely. That is, before there is broad stakeholder acceptance that the results of economic benchmarking are fit for purpose.²²⁹ Economic benchmarking will be one of a number of techniques that we apply when we review the efficiency of historical expenditures. We will consider the relative merits of all techniques when undertaking our assessments. We will also conduct a testing and validation process for economic benchmarking techniques in early 2014. More generally, we are unlikely to use a completely exogenous forecasting approach. The process of making adjustments to base year expenditures, where found to be materially inefficient, is likely to involve a combination of techniques that rely on the NSP's own costs to a measurable degree.

5.3.3 Timeframes

Table 5.1 outlines our proposed timeframes and steps for determining whether we will consider making adjustments to base year expenditures under the revealed cost approach.

Table 5.1 Timeframes for base year review

Publication	Decision
F&A paper and Annual benchmarking report	We will provide an initial view on whether we consider a NSP's historical costs are likely to reflect efficient costs.
Issues paper	In the issues paper, we will publish our first pass assessment using data from the NSP's proposal and base year. This assessment will provide our preliminary view of the proposed opex forecast based upon analysis that can be undertaken within the issues paper timeframes. We intend to run our benchmarking models as part of this process, including economic benchmarking (incorporating an econometric model of opex) and category analysis benchmarking.
Draft determination	We will set out the full base year assessment in the draft determination.
Final determination	We will consider our position in the draft in light of submissions.

We sought submissions on whether we should accept or adjust base year expenditures at the F&A stage. Several submissions noted such a decision cannot be made until after a NSP has submitted its regulatory proposal.²³⁰ Grid Australia noted benefits from us indicating our intended approach at each step leading into the review.²³¹ While we cannot make this decision at the F&A stage, we will aim to provide guidance on our approach at the earliest opportunity. The availability of data affects this

²²⁸ NER clauses 6.5.6(c), 6A.6.6(c)

²²⁹ Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p.

²³⁰ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 15 March 2013, p.6, Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 2.

²³¹ Reference submissions

timing. We may, for example, analyse expenditure incurred before the base year for a NSP, in expectation of providing insight into what is expected once base year data are available. Such an approach is reasonable given the recurrent nature of opex.

The ENA submitted that NSPs must be afforded an opportunity to understand the quantitative benchmarking against which they are assessed.²³² We expect the annual benchmarking reports will provide NSPs with advance notice of our benchmarking modelling results, and thus of our initial views of expenditure efficiency.

In advance of the next determinations we cannot provide an opinion on whether a NSP's costs reflect efficient costs based on the category benchmarking and economic benchmarking techniques in the F&A paper and annual benchmarking report. That said, in line with submissions on this issue, we expect to publish data in our next performance report (to be released later this year) on the relative efficiency of particular NSPs. If data are sufficiently robust, we will provide an early signal of the issues with opex assessments for the NSPs concerned, including those commencing transmission and distribution reviews next year.

For these reviews we intend to consult with stakeholders on the development of benchmarking models before the issues paper. This work may involve testing and validating of economic benchmarking techniques before these reviews in 2014. This will provide stakeholders with an opportunity to understand and comment on our approach prior to its application.

5.4 Capital expenditure approach

We do not expect the techniques that we use to assess capex forecasts will affect our application of the CESS. However the application of the CESS gives rise to issues of inefficient deferral of capex. We may also use our assessment techniques as part of our ex post review of capex.

5.4.1 Capital expenditure sharing scheme

Unlike our approach to assessing opex forecasts, our approach to capex does not necessarily rely on the NSP's historical costs. The application of the CESS is therefore unaffected by our forecasting approach.

In many areas, we propose to use historical capex information in assessing NSP proposed forecasts. Examples are predictive modelling of asset replacement and augmentation volumes, and various costs per unit or per driver measures. These assessments rely only on the capex incentive regime being effective for at least one NSP when benchmarking information applies.

We will consider whether capex forecasts are consistent with the CESS.²³³ This includes the incentives created under the CESS, in forming a view on the efficient and prudent expenditure forecast. Specifically, the CESS creates incentives to efficiently defer expenditure and for NSPs to pursue efficiency gains. However, the CESS could also create an incentive to undertake or defer expenditure in a way that is not prudent and efficient.

The Essential Services Commission of Victoria (ESCV) in 2006 removed the capital expenditure efficiency scheme applied to Victorian DNSPs between 2001 and 2006 because it had difficulties

²³² ENA, *AER efficiency incentives guidelines for electricity networks service providers – response to issues paper*, May 2013, p. 15.

²³³ NER clauses 6.5.7(e)(8) and 6A.6.7(e)(8) require us to consider whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to a NSP.

distinguishing "enduring gains in implementing [capex] programs (such as would arise from establishing more efficient [capex] project management arrangements) from temporary efficiency gains (such as arise from deferral of planned expenditure that does not threaten service performance)."²³⁴ The ESCV considered capex underspends may have resulted from capital investment deferral and that these deferrals may not have been efficient.²³⁵

We are mindful of the CESS creating undesirable incentives and giving rise to similar challenges as faced by the ESCV. We are therefore likely to consider the following when assessing forecast capex:

- the amount and type of capex deferred in the prior regulatory period
- the expenditure incurred relative to what was funded for in previous regulatory periods and the rewards or penalties under the CESS
- various indicators of workload (for example, replacement and maintenance volumes) as well as network performance (including capacity and risk or "health" measures), including what NSPs were expected to deliver, and what they actually delivered over time.

We also note that our application of replacement and augmentation modelling will highlight and take into account network outcomes (e.g. extensions in asset lives or increases in asset capacity utilisation) in the prior regulatory period when estimating prudent and efficient capex over the coming regulatory period. This should also help to limit undesirable incentives to engage in inefficient and unsustainable capex savings.

We expect annual performance reports to compare actual versus forecast spending and various workload and performance indicators. This should give all stakeholders some transparency about how capex savings are being achieved. We may also use this information to help target more detailed reviews of historic spending and spending deferrals during revenue determination processes.

This is consistent with our approach to reviewing opex forecasts when we consider whether the outcomes of forecasts in conjunction with incentive schemes would result in efficient outcomes. The penalty or reward under the CESS is relevant to this consideration. We will adjust the capex forecast if it, taken together with the penalties or rewards of the CESS, leads to an outcome that is not consistent with the long term interests of consumers.

5.4.2 Consistency with ex post review

In some circumstances, we must conduct an ex post review of capex.²³⁶ This includes a review of capex overspends when they occur. We can exclude from the RAB:

- inefficient capex above the capex allowance
- inflated related party margins
- capitalised opex resulting from a change to a NSP's capitalisation policy.

²³⁴ Essential Services Commission Victoria, *Electricity Distribution Price Review 2006-10 Final Decision Overview*, October 2005, pp. 11-12.

²³⁵ Essential services Commission Victoria, *Electricity Price Review 2006-10 October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 Final Decision Volume 1 Statement of Purpose and Reasons*, p. 431.

²³⁶ NER, clauses S6.2.1(g), S6.2.2A, S6A.2.1(g) and S6A.2.2A.

We propose a staged approach to the ex post review. This assessment process will involve increasingly detailed examination of capex overspends, subject to certain thresholds being satisfied. The first step of the proposed review includes assessing the NSP's capex performance including comparing the NSP's performance against other NSPs. The economic and category analysis benchmarking that we propose may be relevant to this consideration. However, in determining whether capex meets the criteria, we must account for only information and analysis that the NSP could reasonably be expected to have considered or undertaken when it undertook the relevant capex.²³⁷

Later steps in the prudency and efficiency review include reviewing asset management and planning practices, and conducting targeted engineering reviews. These assessment techniques are intended to be similar to those that we apply to capex forecasts (considering only the information available to the NSP at the time).

5.5 Service target performance incentive scheme

Our approach to assessing expenditure forecasts will not affect the application of the STPIS. The STPIS was designed to allow for flexibility of assessment approach because it provides an incentive for NSPs to improve their reliability or allow it to decline from historical levels. So, through the STPIS incentive, NSPs are funded to spend money in ways that improve the reliability of networks.

This complements the expenditure forecast assessment requirements under which we may approve only forecasts that reasonably reflect expenditures required to achieve the expenditure objectives. The expenditure objectives include maintaining the reliability of services rather than improving reliability.²³⁸

We may approve expenditure to improve performance if the NSP has a regulatory obligation or requirement to improve reliability. However, this situation will affect the STPIS and our expenditure forecast assessment approach separately and in different ways. Our assessment approach would need to consider the costs of delivering the new level of reliability, whereas we would need to adjust the STPIS targets for the expected change in reliability.

Similarly, we note that providing network services at different levels of reliability imposes different cost requirements on NSPs. We will consider this when benchmarking NSPs.

As mentioned above, the AEMC is reviewing a national framework and method for transmission and distribution reliability in the NEM.²³⁹ We have developed our draft Guidelines on the basis of the current rules, and we will review it if rule changes resulting from the AEMC review require us to change our assessment approach. That said, these changes should not affect our Guidelines because the assessment techniques we employ to examine the efficiency of past and forecast expenditures include consideration of the NSPs' legal obligations in addition to the quality of service or outputs they propose to deliver.

5.6 Demand management incentive scheme

The DMIS is designed to provide incentives for DNSPs to implement efficient non-network alternatives to manage the expected demand for distribution services. It includes a demand

²³⁷ NER clauses S6.2.2 and S6A.2.2

²³⁸ NER clauses 6.5.6(a), 6.5.7(a), 6A.6.6(a) and 6A.6.7(a)

²³⁹ Further information on this review can be found on the AEMC's website: <http://www.aemc.gov.au/Market-Reviews/Open.html> accessed 7 August 2013.

management innovation allowance (DMIA) for demand management related activities. The DMIA is capped at an amount based on our current understanding of typical demand management project costs, and scaled to the relative size of each DNSP's average annual revenue allowance in the previous regulatory period. It provides DNSPs with an allowance to pursue demand management and embedded generation initiatives that may not otherwise be approved under the capex and opex criteria.

We also intend to commence informal engagement on the form of a new demand management incentive scheme, based on the recommendations in the AEMC's final report on its Power of Choice review. This engagement is likely to take place in parallel with the AEMC's DMIS rule change process.

Given the application of the DMIA, we are unlikely to approve expenditure proposals to research demand management and embedded generation.

6 Implementation issues

This chapter provides an overview of the issues that may arise from implementing the Guidelines, the significance of these issues and our measures to mitigate their impact. It discusses how we will manage these various issues in balancing the interests of NSPs and consumers.

In changing from our current approach for assessing expenditure forecasts to the approach in our Guidelines, we may find issues in:

- providing enough time for stakeholders to respond to data requests
- providing ourselves enough time to assess expenditure proposals and publish annual benchmarking reports
- stakeholders' ability to provide data in the short term
- releasing data publicly
- ensuring a workable transition between existing and new data reporting requirements
- using new techniques.

NSPs may face additional costs in the short term when the Guidelines change some of the existing information reporting arrangements. To some extent, these changes could affect data quality and the consistency of reported data between NSPs and over time. Further, we will need to resolve confidentiality issues to determine if and how we can make data available to the public.²⁴⁰

6.1 Proposed approach

We propose the following timeframes for the release of our data reporting templates and subsequent consultation with stakeholders:

- consult on preliminary expenditure information templates (attached to the draft Guidelines, issued in August 2013). This consultation will involve meetings with stakeholders and written submissions on information specified in the draft Guidelines and explanatory statement.
- issue draft RINs under the NEL in September 2013 on all NSPs to collect back cast economic benchmarking data to enable a testing and validation process in early 2014
- issue RINs in late 2013 on all NSPs for the purposes of gathering information for the 2014 benchmarking report and in assessing regulatory proposals submitted in 2014.

In the medium term, use our information gathering powers to collect information from all NSPs for annual reporting, starting in April 2015.

We will consult with stakeholders during early/mid 2014 on the first benchmarking report and on benchmarking issues relevant to network determinations, and then further consult as required. In the short term, we will also request NSPs to continue to collect data based on current information templates in accordance with the annual reporting RINs we have already issued.

²⁴⁰ Refer to the confidentiality guideline for further information.

6.1.1 Data collection timeframes

We aim to gather sufficient information to employ new, standardised assessment techniques for those regulatory resets occurring from 2014, including for the NSW/ACT DNSPs, Transend, TransGrid and Directlink. We must also gather sufficient data for the first benchmarking report due to be published in September 2014.²⁴¹ Subsequent benchmarking reports are due in November of the respective year.²⁴²

We require benchmarking data for both of our benchmarking techniques—economic benchmarking and for category analysis. We propose to request and process data on economic benchmarking techniques earlier than for category analysis. This is possible since consultation on data requirements for economic benchmarking techniques is more progressed. Specifics of these different timeframes are outlined below.

For 2014, standardised data for all techniques will be requested through expenditure specific RINs, with all NSPs required to provide 10 years of back cast information. We will also issue reset RINs on NSPs submitting regulatory proposals in 2014. These NSPs will be required to provide forecast expenditure data in the standard templates, as well as other information required in support of regulatory proposals (for example, detailed demand information).

From 2015 we will obtain data for annual benchmarking reports by issuing regulatory information orders (RIOs). We expect to issue RIOs in April each year, beginning in 2015. These will request annual data for calendar year 2013 and the 2013/14 financial year.

Testing and validation process for economic benchmarking techniques

We intend to issue a draft RIN collecting economic benchmarking data by September 2013, with a final issued in October or November. NSPs will be requested to provide this information by February 2014, allowing the AER to conduct model testing and validation of the economic benchmarking models before we publish benchmarking results.

We are aiming to complete the testing and validation process prior to the lodgement of regulatory proposals in 2014. That said, the precise timings of the testing and validation process depends on the quality of the data provided in response to the RIN. We will set out precise timings for this process in March 2014.

We will also collect some data required for economic benchmarking in the reset RINs. These data would be forecast outputs, inputs and environmental variables.

Data collection for category analysis

Reset RINs issued in February 2014 will collect data for category analysis. This would provide NSPs at least three months after receiving a data request to provide us with their response. The provision of this information will also coincide with the lodgement of regulatory proposals of the NSW/ACT DNSPs, Transend, TransGrid and Directlink in May 2014.

Specific timeframes for NSW/ACT DNSPs, Transend, TransGrid and Directlink

For the sake of clarity, and consistent with our current practice, we will continue to issue separate reset RINs for any NSP subject to an upcoming regulatory determination process. We are likely to

²⁴¹ NER, clause 6.27(d).

²⁴² NER, clause 6.27(c),(d),(e), clause 6A.31(c),(d),(e).

issue final reset RINs following the F&A process. This will occur in February 2014 for the NSW/ACT DNSPs, and Transend, TransGrid and Directlink.

Table 6.1 illustrates our projected timings for the annual reporting process, and provides indicative dates for the issue and response to reset RIN notices out to 2016.

Table 6.1 Indicative timeframe for data requests and NSP responses: 2013 to 2016

Date	Economic benchmarking	Annual reporting milestones*	Reset RIN data
Aug 2013	Release preliminary data templates	Release preliminary data templates	
Sept 2013	Issue draft RIN		
Oct/Nov 2013	Issue final RIN	Issue draft RIN for category analysis data (backcast)	
Feb 2014	RIN responses due Begin data checking/ validation process	Issue final RIN for category analysis data (backcast)	Issue of final RINs for NSW/ACT DNSPs, Transend, TransGrid and Directlink
Mar 2014	Set out precise timings for data checking/ validation process		
May 2014		RIN responses due	Reset RIN responses due for NSW/ACT DNSPs, Transend, TransGrid and Directlink Issue final RINs for SAPN, Energex and Ergon Energy
Sept 2014		Publish first benchmarking report	
Oct 2014			RIN responses due for SAPN, Energex and Ergon Energy
Nov 2014			Issue final RINs for VIC DNSPs
Jan 2015		Issue draft RIO for 2015 benchmarking report	
Apr 2015		Issue final RIO	RIN responses due for VIC DNSPs
May 2015			Issue final RIN for SP AusNet (transmission)
Jul 2015		RIO responses due	
Aug 2015			Issue final RINs for Powerlink and Aurora
Oct 2015			RIN response due for SP AusNet (transmission)
Nov 2015		Publish 2015 benchmarking report	
Jan 2016		Issue draft RIO for 2016 benchmarking report	RIN responses due for Powerlink and Aurora
Apr 2016		Issue final RIO	
Jul 2016		RIO responses due	
Aug 2016			Issue final RINs for ElectraNet and Murraylink
Nov 2016		Publish 2016 benchmarking report	

* Includes economic benchmarking data from 2015

6.2 Reasons for the proposed approach

Our proposed timeframes for data collection provide reasonable time for NSPs to compile data and for us to analyse that data for our assessment purposes. In particular, the timeframes proposed will allow enough time for both us and all stakeholders to consider detailed issues in new and changed reporting requirements. They will also enable proper consideration of new data collected in time for our determinations commencing in 2014, as well as for our first annual benchmarking report.

The proposed timeframes involve consultation on information reporting templates before the Guidelines are finalised. This creates the risk of changes to reporting requirements as consultation on the Guidelines reaches its final stages in late 2014. The Guidelines, however, are unlikely to be prescriptive to the extent they affect detailed data specifications and definitions. Based on productive consultation to date, we also expect stakeholders to support the general specification of techniques and standardised data categories at the aggregate level in the draft Guidelines. Finally, we think it is more important to provide NSPs sufficient time to gather and validate their own data ahead of providing it to the AER for the purposes of benchmarking reports and determinations. This requires RINs to be developed and issued as soon as possible.

In addition to meeting timing constraints, having full visibility and discussion on data templates alongside the draft Guidelines will enable proper consideration of the impact of our new assessment techniques. Such consultation will also provide us with an opportunity to determine what data NSPs can provide in the short term, and how they can do so. It will also allow NSPs to identify commercially sensitive information, thus enabling the AER and other stakeholders to appropriately treat this information ahead of regulatory determination processes if time to consider such matters is limited.

In our issues paper, we invited submissions on the timing, frequency and composition of our data requests. Comments made by stakeholders were as follows:

- The MEU stated that all NSPs should commence collecting the data in the format required as soon as possible, even though application to their specific revenue reset might be some time away.²⁴³
- Aurora submitted that we should issue RINs as soon as possible to give NSPs sufficient time to clarify our requirements and make the needed information system changes.²⁴⁴
- The ENA and a number of NSPs considered that the timing and issue of respective RINs should align with each NSP's regulatory period.²⁴⁵

We consider our proposed timings are consistent with this feedback.

The benchmarking process itself will likely identify issues not yet raised in consultation, and will include data testing to identify errors and anomalies. We expect to follow an open consultation process before publishing the first benchmarking report as well as draft decisions. We will consult as part of the testing and validation process for economic benchmarking techniques and likely engage further on category analysis around mid-2014 after we have received all the data we require. This consultation will be particularly important for those NSPs submitting regulatory proposals in May 2014 that will do so without full visibility of our new techniques. We recognise this creates a potential

²⁴³ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 20.

²⁴⁴ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, pp. 8–9.

²⁴⁵ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 17.

disadvantage as these NSPs will not be able to modify their proposals for the AER's assessment approach. The early data collection and testing of economic benchmarking models in early 2014 may assist in this regard.

The issuing of reset RINs will continue to coincide with the timing of F&A processes for each respective NSP. We will also consult with NSPs to manage any potential overlaps or inconsistencies between what we request annually and what we request separately for determination processes.

6.3 Other implementation issues

Stakeholders raised some issues that may arise in transition to expanded and consistent data reporting. We intend to consult further with NSPs in managing these issues, which include data provision, quality, back casting and confidentiality.

6.3.1 Short term data provision

Some NSPs may be unable to provide certain data in the short term, but they can provide much of it. NSPs already have data that we intend to use for economic benchmarking. Similarly, when considering the information that we need for category assessments, we are mindful of the data that NSPs already report.

During consultation on the Guidelines, NSPs noted their ability to provide new data may be affected by the visibility of costs incurred by contractors, as well as the time taken to implement new data reporting systems:

Some NSPs do not currently request specific information from some external providers under existing service contracts. Contractors are not obliged to provide the data if it is not part of their current contractual arrangement. Because contractual periods typically run for a number of years, it may be unreasonable to expect data for some time in some categories in the short term.²⁴⁶

NSPs may need to implement new data reporting systems and processes to comply with our data requirements. It will take time for NSPs to put systems and processes in place.

User representatives urged us to work to resolve potential barriers to introducing new techniques as identified by NSPs. For example, while PIAC acknowledged some issues raised are transitional and some more substantive, it:

...would be most concerned if these difficulties led to undue delays in the implementation of an effective suite of benchmarking tools, albeit PIAC recognises that their use would need to be qualified somewhat in the next determination round.²⁴⁷

NSPs are expected to provide all data we request. If they provide legitimate reasons for being unable to do so, we expect them to reasonably approximate or estimate these data. We will also consult with NSPs on reasonable timeframes to provide and comply with the data request.

6.3.2 Data quality

We expect NSPs will be able to provide most data at a high standard, but recognise some data may not be robust. Instances of poor quality data may be high initially as NSPs implement new record keeping and reporting processes. Such data quality limitations may prevent us from immediately

²⁴⁶ AER, 'Meeting summary - Operating & maintenance expenditure', *Workshop 11: Category analysis work-stream - Opex (Transmission & Distribution)*, 11 April 2013, p. 5.

²⁴⁷ PIAC, *Seeking better outcomes: PIAC submission to the AER's Issues Paper – Expenditure forecast assessment guidelines*, 20 March 2013, p. 15.

using certain techniques in the annual benchmarking reports or in determinations. However, we will consider data quality issues when performing our analyses and consult with stakeholders when appropriate.

In workshops, some NSPs raised concerns about providing back cast data. They considered their internal data may be suitable for planning but it may not have been audited. As such, an auditing requirement may present a difficult data quality hurdle for back casting. Some NSPs also noted that to obtain director sign off on the quality of the data may impact on the length of time required to fulfil our data requirements.²⁴⁸ The ENA stated in its response to the issues paper that we should consider relaxing information certification standards, so that NSPs can provide information that may be useful if not 100 per cent accurate.²⁴⁹

We have considered the concerns of NSPs and the ENA. However, the information we are seeking will ultimately impact electricity prices, so it should be of a high quality and reliable. The Australian Government has endorsed us using economic benchmarking techniques and ensuring we are able to access the information to do so,²⁵⁰ and we intend to collect the data we need. While it may not be a simple task to provide reliable back cast data, we expect NSPs to commit to allocating the requisite resources to ensure back casting is conducted properly.

We acknowledge that our new reporting requirements differ in some respects from the past but it is a priority for us to gather robust data that is consistent across the NEM. Therefore, we will require back cast data to be independently audited. It is acceptable for NSPs to make assumptions or exercise judgment to comply with our data requirements. However, NSPs must be transparent about the assumptions and processes they use. We will require auditors to review compliance with our framework.

Reasonable (positive) assurance on back cast information should be provided on financial and non-financial data where possible, in accordance with ASA 800 and ASAE 3000, respectively. We note the concern expressed by NSPs about the time involved, but we would expect NSPs to be making the necessary preparations to provide information to us in light of the workshops and additional consultation we have held on data requirements (particularly for economic benchmarking).

In the interests of receiving data as soon as possible, we will accept data from NSPs once it has been audited but prior to Board signoff. NSPs can subsequently provide Board signoff and changes to the data and audit report (if applicable). We consider the timeframes in section 6.1.1 allow sufficient time for NSPs to provide us with audited data prior to signoff. Attachment A discusses back casting of data in more detail.

6.3.3 Data release and management

We are developing a benchmarking database and are considering how to make it accessible to stakeholders. In consultation, both consumer representatives and NSPs underlined the importance of being able to obtain this information to better engage in the price/revenue determination process and understand our decisions, noting confidentiality concerns.²⁵¹ All stakeholders noted they would

²⁴⁸ AER, *AER expenditure workshop no. 17 meeting summary – economic benchmarking applications*, 6 June 2013, p. 4.

²⁴⁹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 18.

²⁵⁰ Australian Government, *The Australian Government response to the productivity commission inquiry report – Electricity Network Regulatory Frameworks*, June 2013, pp. i-ii, 3-9.

²⁵¹ AER, 'Meeting summary - DNSP outputs and environmental factors', *Workshop 12: Economic benchmarking techniques work-stream - Measurement of outputs and environmental factors (Distribution)*, 30 April 2013, p. 3.

consider these data useful for performing their own benchmarking analyses and obtaining information on NSPs' performance. The early release of data would help achieve these outcomes. It would also help stakeholders to engage with us in our benchmarking model testing and validation, resulting in better decisions for the benefit of both consumers and NSPs.

We will need to consider how we release data to the public, address any confidentiality concerns, and ensure transparency of the data released. We will also need to consider how best to manage data supplied formally through RINs or RIOs, and informally through bilateral requests. Nevertheless, we expect the majority of data provided to us by NSPs will be included in the database and released publicly in a routine manner. We recognise this data disclosure may raise confidentiality issues and expect these to be addressed quickly in accordance with our new confidentiality Guidelines.²⁵² Confidential data should be identified as RINs are developed, hence we expect the process for eventually releasing this information will commence well ahead of it being actually obtained by us.

It may take longer than usual to publish data obtained through our first round of RINs. This is because of the need to establish and test internal processes for the storage and release of data. This process will likely be quicker for subsequent data requests.

6.3.4 Existing reporting requirements

We may request NSPs continue to provide expenditure and supporting data in accordance with the annual reporting RINs already issued by us. New data may not reconcile with existing data sets, and the quality of some data provided may not be ideal for our analysis in the short term. NSPs' provision of data in the same format as their current determinations is important in reconciling expenditure outcomes to what was proposed and determined at the time of previous price reviews. For this reason, dual reporting requirements may exist until the end of each NSP's current regulatory control period. For the sake of clarity, we are not going to ask for forecasts based on existing annual reporting RINs.

We consider the timeframes proposed for the new data requests do not clash with most of the existing reporting obligations. Non-Victorian DNSPs provide RIN responses in November/December each year. Under the proposed timeframe, these DNSPs will receive the new benchmarking data request in November 2013, after they submit the current RIN. TNSPs must provide their regulatory accounts no later than four months after the end of their regulatory accounting years.²⁵³ However, the Victorian transmission regulatory accounting year does not align with other jurisdictions, so we intend to consult with TNSPs to resolve any issues that may arise.

6.3.5 Issues in applying assessment techniques

Transitional issues will arise as we develop assessment techniques. These issues include those associated with data requirements (section 6.3.2), but also the effectiveness of the techniques. We noted a couple of limitations in our issues paper:

Our experience and that of other regulators is that no single assessment technique is perfect and many require (at the request of the regulator or of regulated businesses) further data that cannot always be contemplated at the time the technique is defined conceptually.

Some techniques may appear robust and agreed upon at an early stage, however, ultimately they may be abandoned or subject to revision if they cannot produce sufficiently reliable and accurate results.²⁵⁴

²⁵² AER, *Confidentiality guidelines issues paper*, March 2013, p. 6.

²⁵³ AER, *Electricity transmission service providers information guidelines*, September 2007, p. 11.

²⁵⁴ AER, *Guidelines issues paper*, December 2012, p. 36.

With these issues in mind, we may not rely on some techniques proposed in the Guidelines in the short term, or we may place less weight on these techniques. Some approaches and techniques are less likely to be affected because we used them in previous determinations, including the repex model and the revealed cost approach to forecasting opex.

We will refine our benchmarking techniques as we develop the benchmarking report. This refinement may occur when we identify a more appropriate alternative approach to compare expenditures across NSPs. For determinations, the weight we place on the new techniques in the Guidelines is likely to change over time. In particular, we expect to rely more on high level techniques (including benchmarking) and less on more intrusive techniques (including detailed engineering and project reviews), whereas we relied heavily on the latter in the past (refer to section 2.2 on our previous assessment approach).

Another issue that we face in applying new assessment techniques is our requirement to stagger determinations for NSPs. While the staggered timing creates difficulties for obtaining consistent data, it allows us to review and refine our data and techniques incrementally rather than on a wholesale basis. This point was highlighted by the ENA in its submission to the issues paper.²⁵⁵

²⁵⁵ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 19.

Attachments

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A Economic Benchmarking

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

A.1 Proposed approach

Our proposed approach to economic benchmarking covers two matters:

1. the selection and application of economic benchmarking techniques and
2. our approach to data.

These are outlined separately below.

A.1.1 Economic benchmarking techniques

We propose to take a holistic approach to the selection of particular economic benchmarking techniques; however, we intend to apply them consistently.

Holistic approach to selection of economic benchmarking techniques

We are taking a holistic approach to economic benchmarking. This means that we will not specify economic benchmarking techniques in our Guidelines but rather determine the application of economic benchmarking techniques at the time of determinations.

We will select economic benchmarking models based on the availability and quality of data, and intended use. Some models may simply be used to cross-check the results of other techniques. At this stage, it is likely we will apply multilateral total factor productivity (MTFP), data envelopment analysis (DEA) and an econometric technique to forecast operating expenditure (opex).

We anticipate including economic benchmarking in annual benchmarking reports.

Applications of economic benchmarking

We are likely to use economic benchmarking to (among other things):

1. measure the rate of change in, and overall, efficiency of NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.
2. develop a top down forecast of total expenditure.
3. develop a top down forecast of opex taking into account:
 - the efficiency of historical opex
 - expected rate of change for opex.

A.1.2 Approach to data

We have developed a preferred model specification for economic benchmarking. However, we intend to collect information and test alternative model specifications. This is outlined below.

Preferred model specification

The preferred model specifications are our view of NSPs' outputs, inputs and environmental variables that should be used for efficiency measurement. We based these specifications on our knowledge of NSP operations and the feedback we received from submissions and workshops on the data requirements for economic benchmarking.

The specifications provide up front guidance to stakeholders on our views on the variables that we consider should be used for efficiency measurement and to provide a starting point to test as part of our testing and validation process. However, economic benchmarking is an iterative process that we aim to improve, so we expect to revisit and test our preferred model specification over time. We have also set out alternative specifications to use as a basis of comparison for our preferred specification during our testing and validation process.

Table A.1 shows our preferred DNSP output and input specification. It is based on Economic Insights' recommended DNSP specification.²⁵⁶ Table A.2 shows our preferred TNSP output and input specification which is also based on Economic Insights' recommended TNSP specification.²⁵⁷ Our shortlist of outputs, inputs and environmental variables are discussed below.

Table A.1 Preferred DNSP specification

Quantity	Value	Price
Outputs		
Customers (no.)	Revenue*Cost share	Value/Customers
System capacity (kVA*kms)	Revenue*Cost share	Value/kVA*kms
Interruptions (customer minutes)	-1*Customer minutes*VCR per customer minute	-1*VCR per customer minute
Inputs		
Nominal opex/Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWWS WPI and five ABS producer price indexes
Overhead lines (MVA-kms)	Annual user cost (return of and on overhead capital)	Overhead annual user cost/MVA-kms
Underground cables (MVA-kms)	Annual user cost (return of and on underground capital)	Underground annual user cost/MVA-kms
Transformers and other (MVA)	Annual user cost (return of and on transformers and other capital)	Transformers and other annual user cost/ MVA

Abbreviations: VCR – value of customer reliability, ABS – Australian Bureau of Statistics, EGWWS – electricity, gas, water and waste services, WPI – wage price index, MVA – megavolt amperes, kVA – kilovolt amperes.
Source: Economic Insights and AER analysis.

²⁵⁶ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 83.

²⁵⁷ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 90.

Table A.2 Preferred TNSP specification

Quantity	Value	Price
Outputs		
System capacity (kVA*kms)	Revenue*Cost share	Value/kVA*kms
Entry and exit points (no.)	Revenue*Cost share	Value/No.
Loss of supply events (no.)	-1*loss of supply events*average customers affected*VCR per customer interruption	-1*average customers affected*VCR per customer interruption
Aggregate unplanned outage duration (customer mins)	-1*customer mins*VCR per customer minute	-1*VCR per customer minute
Inputs		
Nominal opex/Weighted average price index	Opex (for prescribed services adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWWS WPI and five ABS producer price indexes
Overhead lines (MVA-kms)	Annual user cost (return of and on overhead capital)	Overhead annual user cost/MVA-kms
Underground cables (MVA-kms)	Annual user cost (return of and on underground capital)	Underground annual user cost/MVA-kms
Transformers and other (MVA)	Annual user cost (return of and on transformers and other capital)	Transformers and other annual user cost/ MVA

Abbreviations: VCR – value of customer reliability, ABS – Australian Bureau of Statistics, EGWWS – electricity, gas, water and waste services, WPI – wage price index, MVA – megavolt amperes, kVA – kilovolt amperes.

Source: Economic Insights and AER analysis.

Holistic approach to data

We are seeking a data set that is broader than that needed for our preferred specifications, and also broader than that just required to apply DEA, MTFP and econometric modelling of the opex cost function. It also means other techniques (such as stochastic frontier analysis), which cannot be applied in the short term, can be used in the future once enough data are available.

Our holistic approach to data will allow us to adopt and test different model specifications and conduct sensitivity analysis. The data obtained for economic benchmarking will be subject to extensive consultation as part of our data validation and model testing process.

We consider the obligation to provide data that may not be part of our preferred model specification is not overly burdensome. NSPs are likely to gather the data already; we already receive, for example, energy delivered and customer numbers disaggregated by customer type as part of our annual reporting requirements.

A.2 Reasons for proposed approach

We outline the reasons for our proposed approach to economic benchmarking below.

A.2.1 Application

In our issues paper we proposed to use economic benchmarking to:

- provide an overall and higher level test of relative efficiency, which may highlight issues that may be overlooked during lower level and detailed analysis²⁵⁸
- facilitate benchmarking that may not be possible as part of the category analysis (given data availability), including as a transitional measure
- reinforce findings made through other types of analysis, or otherwise highlight potential problems in assessment methods or data.

We received a number of submissions on our proposed approach to apply economic benchmarking. Further, we refined our proposed approach since releasing the issues paper. We address submissions and outline the reasons for our proposed approach in the following sections.

General comments on economic benchmarking

A number of submissions on the issues paper commented on our proposed application of economic benchmarking. Several supported our proposed approach.²⁵⁹ The PC also commented on the application of benchmarking, recommending we:

- at this stage, use aggregate benchmarking to inform (but not as the exclusive basis for) determinations
- begin (ongoing) development of detailed benchmarking performance and control variables, with periodic review for relevance and compliance costs and publish benchmarking results and data.²⁶⁰

Our proposed approach is consistent with the PC's comments. It is our intention to develop benchmarking techniques to be used to better inform our determinations. Economic benchmarking will be used in conjunction with a number of other techniques to review expenditure forecasts.

Some submissions also noted the limitations of benchmarking and cautioned against its use deterministically.²⁶¹ We are aware of the limitations of economic benchmarking, noting that all assessment techniques have flaws. That said, we consider economic benchmarking has several advantages:

- It accounts for the multiple inputs and outputs of network businesses.
- It may alleviate the need for detailed cost reviews.
- It is transparent, replicable and uses the revealed performance data of NSPs.

²⁵⁸ For example, analysis of individual categories of expenditure may not account for the substitutability of inputs. This may make it difficult to distinguish between inefficient expenditure at the category level and expenditures that appear anomalous due to the selection of inputs.

²⁵⁹ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p.17.

SP AusNet, *Expenditure Forecast Assessment Guidelines—Issues Paper*, 15 March 2013, p. 2.

AER, 'Meeting summary', *Consumer Reference Group (CRG) Meeting No. 4*, 23 May 2013, p. 10.

²⁶⁰ Productivity Commission, *Electricity network regulatory frameworks – inquiry report*, Volume 1, 9 April 2013, p. 41.

²⁶¹ CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 6;

Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 18 March 2013, p. 13;

Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, pp. 3-4;

Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, pp. 4-5;

ActewAGL, *Response to Expenditure forecast assessment guidelines paper*, 15 March 2013, p. 2;

SP AusNet, *Expenditure Forecast Assessment Guidelines—Issues Paper*, 15 March 2013, p. 3.

We intend to apply economic benchmarking in conjunction with other expenditure assessment techniques. However, we will not preclude placing weight on it in determining expenditure allowances. If, on the balance of evidence (accounting for submissions), we consider economic benchmarking provides the most appropriate forecast, then we will use it to set expenditure allowances. At this stage, it is too early to form a view on the appropriate weight to apply to assessment techniques.

CitiPower, Powercor and SA Power Networks stated that while DNSPs should have the opportunity to identify and explain uncontrollable factors that influence differences in expenditure across NSPs, we should not place the onus of proof on DNSPs to provide evidence demonstrating these differences.²⁶² We expect NSPs to justify their expenditure proposals—particularly where they appear inefficient. However, we intend to provide stakeholders with many opportunities to comment on economic benchmarking data, modelling and regulatory applications. We will publish economic benchmarking data. Further we will consult on the development of economic benchmarking techniques and publish the results of economic benchmarking in issues papers and annual benchmarking reports.

Ausgrid submitted that benchmarking a business's own performance over time should receive greater weighting in the AER's assessment framework, as this obviates many of the concerns associated with selecting appropriate domestic or international benchmark peers and adequately addresses a business's unique operating characteristics.²⁶³ We note these concerns about comparing efficiency across networks. We prefer to use the revealed costs of networks where we are satisfied they are efficient. However, we consider it appropriate to deviate from an NSP's historical costs where they appear materially inefficient.

Holistic approach

Our draft position is to apply a holistic approach to the selection of economic benchmarking techniques. This means that we will not set out our proposed economic benchmarking techniques and model specification in the Guidelines. Rather, we will set them out in the framework and approach paper, the approach we proposed in the issues paper. A number of submissions supported this position.²⁶⁴

Ergon Energy commented that selecting one economic model over another will result in subjective decision making and increase the chance of regulatory error. This was because each economic benchmarking technique is likely to provide different results.²⁶⁵

Some judgment is inevitable, but we propose to select economic benchmarking techniques based on the principles for selecting assessment techniques. Further, we do not accept that different economic benchmarking techniques will necessarily produce different results. However, if necessary, we will test this as part of our model testing process. If different models produce different results, we will consider this when applying economic benchmarking.

²⁶² CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 6.

²⁶³ Ausgrid, Endeavour Energy and Essential Energy, *NSW DNSP submission on Forecast Expenditure Assessment Guideline-Issues Paper*, 14 March 2013, p.1.

²⁶⁴ SP AusNet, *Expenditure Forecast Assessment Guidelines—Issues Paper*, 15 March 2013, p. 3.; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 12; Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 10.

²⁶⁵ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 5.

Some submissions suggested we should provide greater rewards for NSPs that push out the efficient frontier.²⁶⁶ We are considering the rewards for NSPs that make efficiency gains in our review of the incentive schemes. However, it should be noted we are constrained to only approve prudent, efficient forecasts. Using economic benchmarking may reward efficient businesses by simplifying and potentially fast-tracking expenditure proposal reviews.

Application of economic benchmarking

We will likely apply economic benchmarking to (among other things):

1. measure the rate of change in, and overall, efficiency of NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.
2. develop a top down forecast of total expenditure.
3. develop a top down forecast of opex taking into account:
 - the efficiency of historical opex
 - expected rate of change for opex.

As part of the workshop consultation, we released an illustrative spreadsheet that provides example applications of economic benchmarking using a number of economic benchmarking techniques.²⁶⁷ We expect to apply economic benchmarking as we outlined in the example. However, ultimately, we will decide how to apply it at the time of individual determinations, based on the availability and quality of data.

Our current view is that we will apply three economic benchmarking techniques:

- MTFP— this will be used primarily to measure the overall efficiency and productivity of NSPs.
- DEA— this is a more limited technique than MTFP, because it cannot incorporate as many input and output variables and because it requires more data. Therefore, we propose using it to cross-check the results of the MTFP analysis. It may be possible to decompose the efficiency scores of DEA to identify different types of inefficiency.
- An econometric technique to forecast operating expenditure—this will be used to develop a top down forecast of opex.

Review of relative efficiency and change in efficiency and productivity

As discussed in chapter 3 we must only accept forecasts of expenditure where they reflect the opex and capex criteria meeting the opex and capex objectives. Economic benchmarking measures the relative efficiency of historical costs and the rate of change in productivity and efficiency of historical costs.

The efficiency of historical costs is relevant to considering whether an NSP is responding to incentives. Where NSPs are not responding to incentives (or not responding quickly enough) it may not be appropriate to base an NSP's forecasts purely on its historical expenditures. Economic

²⁶⁶ CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 12.

²⁶⁷ The models, papers and presentations for this workshop have been published on our website at: <http://www.aer.gov.au/node/20627>.

benchmarking will be one of several techniques that we will use when considering the efficiency of historical costs.

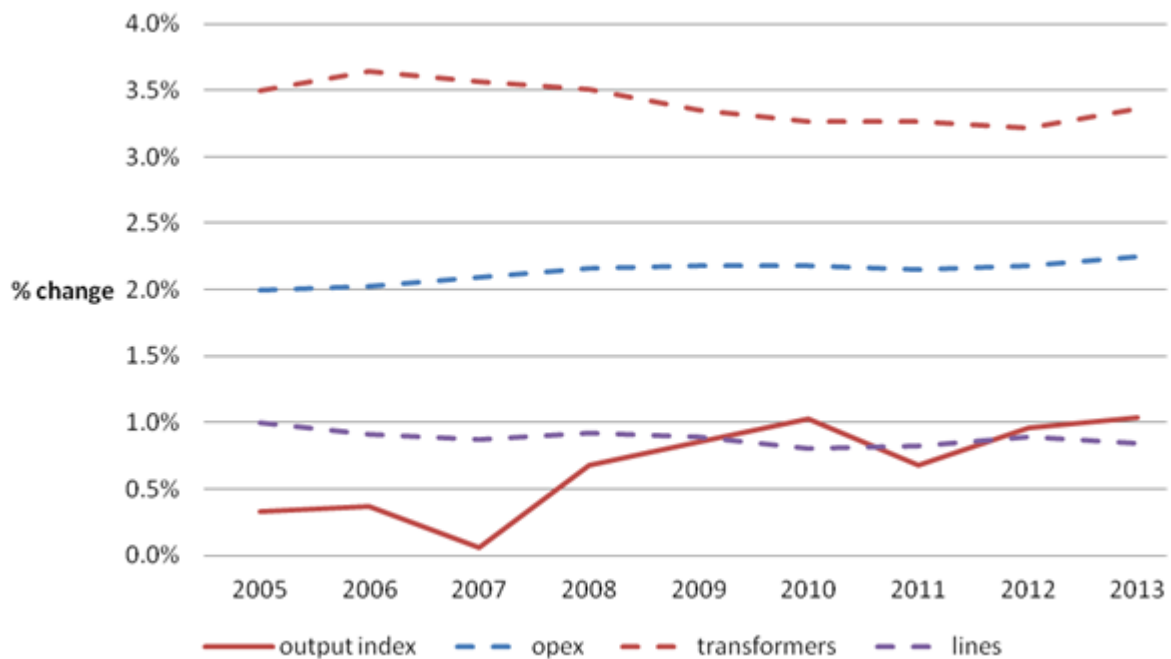
Economic benchmarking, together with other tools such as category analysis, can also provide guidance to targeted reviews of expenditure. For example, where an NSP appears to be relatively inefficient or does not show improving efficiency performance, economic benchmarking results can be decomposed to identify the sources of inefficiency.

Identifying sources of efficiency change

The examination of economic benchmarking results can highlight areas of expenditure forecasts that warrant further investigation. We can identify the sources of changes in efficiency, either from changes in inputs or outputs. This includes separating the efficiency scores into their individual components.

Figure A.1 illustrates possible components of a TFP index. The index is split into three input components (opex, lines and transformers) and the aggregate output component. This illustrates that, although aggregate output increased, the increase in inputs was much greater. Historical transformer input is outstripping the growth of the other inputs markedly. Further, opex increased steadily over the period. Finally, the increase in the length of lines was stable. Based upon this example, historical transformer and opex growth appear to be the sources of the change in TFP and may warrant detailed review.

Figure A.1 Decomposition of change in TFP



Source: AER analysis

Consideration of efficiency components

We consider productive efficiency is most relevant for assessing cost forecasts. Productive efficiency is achieved where firms produce their goods and services at lowest cost.²⁶⁸ The productive efficiency scores derived from economic benchmarking can also be deconstructed into their individual components (Table A.3). In a regulatory context, it may be necessary to consider the different components of efficiency separately. It may not be possible for NSPs to be scale efficient because they have little control over their outputs, for example. Further, there may be little scope for relatively efficient businesses to achieve efficiencies from technical change.

Table A.3 Definitions of efficiency

Efficiency measure	Description
Technical efficiency	This is a firm's ability to achieve maximum output given its set of inputs.
Input mix allocative efficiency	This is a firm's ability to select the correct mix of input quantities to ensure the input price ratios equal the ratios of the corresponding marginal products (that is, the additional output obtained from an additional unit of input).
Cost efficiency	This is a firm's ability to produce a given level of output at minimum cost given the input prices it faces. Cost efficiency is achieved when both technical efficiency and input mix allocative efficiency are achieved.
Output mix allocative efficiency	This is a firm's ability to select the combination of output quantities in a way that ensures the ratio of output prices equals the ratio of marginal costs (that is, the additional cost corresponding to the production of an additional unit of product).
Scale efficiency	This measures the degree to which a firm optimises the size of its operations. A firm can be too small or too large, resulting in lower productivity associated with not operating at the technically optimal scale of operation.
Technical change	This is a change in the amount of inputs required to produce an output or a combination of outputs. Productivity change over time can be decomposed into technical change, scale efficiency change, input/output mix efficiency change and technical efficiency change.

Source: Coelli T, Estache A, Perelman S and Trujillo L, A primer on efficiency measurement for utilities and transport regulators, World Bank Publications, 2003, pp. 11–12.

Some stakeholders submitted we should focus on promoting dynamic efficiency, stating the greatest value at stake for customers is ensuring the appropriate timing and scope of investment.²⁶⁹

We consider using benchmarking to measure and report relative productive efficiency will promote dynamic efficiency. Dynamic efficiency relates to industry making timely changes to technology and products in response to changes in consumer tastes and productive opportunities.²⁷⁰ The responsiveness of industry is difficult to measure. However, dynamic efficiency can be promoted through appropriate incentives and competition.

Economic benchmarking does this. It creates reputational risk for NSPs, giving them a stronger incentive to adopt new technologies and business practices and to invest appropriately. Further, reporting productive efficiency accounting for all the factors of production provides information on

²⁶⁸ Independent Inquiry into National Competition Policy (F Hilmer, Chair), *National Competition Policy*, Australian Government Publishing Service, Canberra, 1993.

²⁶⁹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 5; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 11–2.

²⁷⁰ Independent inquiry into national competition policy (F Hilmer, Chair), *National competition policy*, Australian Government Publishing Service, Canberra, 1993.

dynamic efficiency. Using economic benchmarking in determinations also creates competitive pressures across NSPs, which will promote dynamic efficiency. If we forecast costs at the productively efficient level, NSPs that gain efficiencies through better management or innovation will retain a proportion of the efficiency gains.

The ENA acknowledged it is important for the regulator to examine productive efficiency, but submitted it is difficult for the regulator to determine with any degree of certainty whether a firm is productively efficient and, if not efficient, how it should improve efficiency. To make any meaningful contribution on this front, the ENA submitted we must be able to replicate the full knowledge and decision making processes of each NSP. This cannot be achieved through benchmarking alone.²⁷¹

We disagree with this submission. Measuring productive efficiency does not require replicating the full knowledge and decision making process of each NSP, nor is it the task of the regulator to be in such a position in order to perform its primary role of assessing the efficient costs of NSPs. The role of the regulator is not to micro-manage NSPs. Productive efficiency requires measuring a NSP's inputs, outputs and environmental factors.

Consideration of the appropriate benchmark

The benchmark level of efficiency is the level of efficiency against which NSPs are compared and should be able to operate at. We could set it at a number of possible levels, such as the top quartile middle or revealed frontier. This will depend on the robustness of the data and the model specification. In determining the benchmark level of efficiency performance we will consider the reliability of data and the potential error of expenditure assessment techniques. We do not propose to set an appropriate benchmark until the testing and validation process concludes.

It is important to note that we cannot measure the actual efficient frontier. All we can measure is a revealed efficiency frontier. This is because data may contain errors, there is a limit to the number of variables that can be incorporated, and we are only sampling a subset of all NSPs worldwide.

The PC agreed there will always be error in measuring the efficient frontier. It recommended using a yardstick approach for judgments about allowable revenues—that is, choose a firm close to, but not at, the efficiency frontier.²⁷² The ENA argued against using the revealed frontier as the benchmark.²⁷³

We consider that any forecasting approach is subject to error. Judgement is required when interpreting the results of any forecast. Further, it is quite likely that the efficient frontier will be further out than the revealed frontier. This is because estimation techniques outlined above will be used to measure the relative efficiency of Australian NSPs only. However, at least some international NSPs are likely to be more efficient than those in Australia. As such, the revealed frontier may already be conservative.

Depending on the technique used and its assumptions, the estimated efficient frontier may differ. Given that differing techniques may estimate the frontier in different manners, we will consider how they measure the frontier in the selection of the efficient benchmark.²⁷⁴

²⁷¹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 5.

²⁷² Productivity Commission, *Electricity network regulatory frameworks – inquiry report*, Volume 1, 9 April 2013, p.31

²⁷³ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 5.

²⁷⁴ The different approaches to measuring the frontier using economic benchmarking are set out in our Issues Paper.

The appropriate benchmark may also differ depending on the sensitivity of benchmarking results to technique and model specification. When there is uncertainty about the appropriate model specification and different specifications provide different results, it may be necessary to use the results cautiously.

The CRG expressed a preference for the use of one benchmark firm.²⁷⁵ The efficient frontier will be estimated using economic benchmarking techniques incorporating all NSPs (transmission and distribution will be separately benchmarked). Due to the fact that NSPs produce multiple outputs there may well be a number of firms on the efficient frontier. The number of firms on the efficient frontier may also differ depending on the benchmarking technique applied. We do not consider that it is appropriate to determine the number of benchmark firms until the results of economic benchmarking become available.

Measurement of the rate of change in productivity

The measurement of the rate of change in productivity is also an important consideration when assessing expenditure forecasts. It is expected NSPs will become progressively more productive and efficient over time, and this should be reflected in efficient and prudent forecast expenditure. The change in productivity may indicate potential productivity change for the near future. Note that cost escalation over time incorporates:

- input price changes
- output growth
- productivity changes, including:
 - technical change (industry frontier shift)
 - technical efficiency change (efficiency catch up)
 - scale efficiency change

The rate of productivity change may differ depending on a NSP's relative efficiency. Several participants commented on the ability of NSPs to make productivity improvements. ENA noted some of its members have been subject to incentive regulation for more than 15 years, making large efficiency gains in the process and moving towards the efficiency frontier. For many of these businesses, large step changes in efficiency will not be possible, with only gradual year-on-year improvements being realistic.²⁷⁶ We expect relatively efficient NSPs to be technically efficient and agree it is not appropriate to expect them to achieve further technical efficiencies. However, they should be able to achieve technical change in line with the rest of the industry.

Workshop participants proposed 'industry wide productivity' must include both private and public NSPs. Some suggested private providers are likely to be more productive and public providers less so. However, the small number of NSPs in Australia means it would not be reasonable to exclude

²⁷⁵ AER, 'Meeting summary', *Consumer Reference Group (CRG) Meeting No. 4*, 23 May 2013, p. 9.

²⁷⁶ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 15.

private providers, because the productivity measure would be based on an even smaller number of NSPs.²⁷⁷

We propose to include all NSPs in our benchmarking analysis regardless of ownership in order to review their relative efficiencies, as well as productivity changes and the sources of productivity changes in the past. However, for the purpose of forecasting efficient cost for the next regulatory period, we need to carefully consider the productivity improvement potential that can be achieved by each NSP. It can be the case that, for those businesses on or close to the frontier, large technical efficiency change in the past should not be factored into their forecasts of future productivity change. However, where it is expected that NSPs may be able to achieve further technical efficiency improvement, then this will be factored into forecasts.

MEU submitted that the cost reduction process needs to be continual, but that it should result in moderate downward movement in costs. It would be inappropriate to declare a large reduction in allowed costs (regardless of the correctness of the decision) because this might result in other untoward outcomes such as reduced reliability.²⁷⁸

We consider the expected change in productivity will depend on the source of productivity change:

- Technical change is expected to be consistent and incremental for all NSPs.
- Technical efficiency change will depend on the source of technical inefficiency:
 - If technical inefficiency is associated with opex, then it might be reasonable to assume that this can be eliminated quickly as opex is flexible in the short run.
 - Technical inefficiencies associated with capital inputs may take longer to achieve, given the long term nature of capital investment.
- Scale efficiency change will be aligned with the growth in outputs and the scale of operation.

NSPs also suggested the Guidelines should identify the timeframe over which efficiency gains might be realised.²⁷⁹ Our view on the incorporation of efficiency gains into forecast expenditure is detailed in section 4.1 above.

Total cost counterfactual forecast

Using the forecast of productivity change and historical costs we intend to develop a top down forecast of total costs. This forecast would provide a counterpoint to proposals—the counterfactual. The total cost counterfactual forecast will be one of a number of techniques applied in the first pass assessment of regulatory proposals.

Figure A.2 illustrates this potential application by presenting annual total cost estimates and forecasts proposed by an NSP (in columns) and reference annual total costs established under the economic benchmarking approach (the line). The economic benchmarking approach is developed by taking

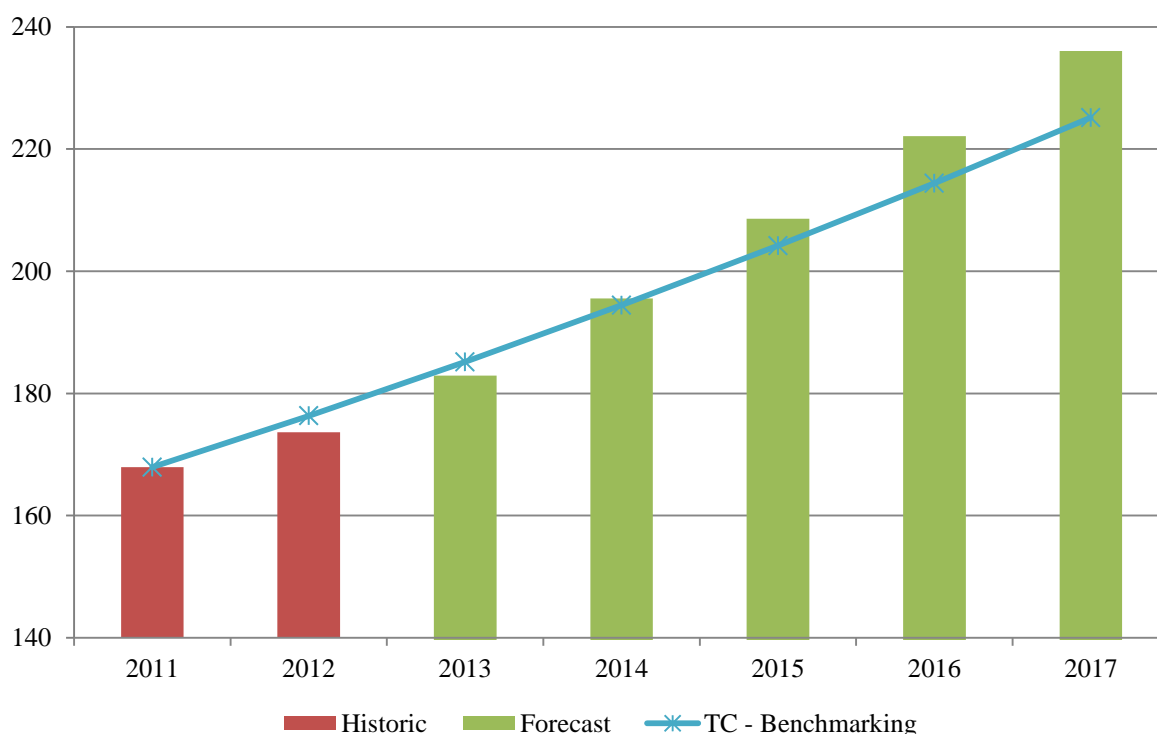
²⁷⁷ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 4.

²⁷⁸ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 10.

²⁷⁹ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 3.

historical expenditures and escalating them by the forecast rate of change in cost that accounts for potential input price change, output growth, and efficiency and productivity gains.

Figure A.2 Comparing Total Cost Forecasts²⁸⁰



Source: AER analysis

In this example, for four years of the forecast regulatory period (2014 to 2017), the NSP proposed higher total costs than those suggested by economic benchmarking. In a net present value sense, total costs proposed by the NSP for the forecast regulatory period are higher than the benchmarked total costs. The discrepancy in forecast costs may reflect a different view about demand outlook, input requirements and the potential scope for productivity and efficiency improvements. We will need to consider these differences in order to form a view on efficient costs.

Top down opex forecast

We also propose to use economic benchmarking to develop a top down forecast of opex that would:

- measure the relative efficiency of the opex base year and develop a potential substitute base year
- forecast the rate of change in opex, incorporating expected efficiency change based on historically observed efficiency change.

The resulting opex forecast for the forthcoming regulatory period provides an alternative set of estimates to NSP proposals. This proposed economic benchmarking application builds on the current revealed cost base-step-trend forecasting approach by:

²⁸⁰ Where there is disagreement on input price changes and output growth rates, we may need to make two separate forecasts. This would illustrate the materiality of the differences in expected output growth and input price changes.

- identifying potential inefficiency in the base year opex. This allows for the immediate or progressive removal of opex inefficiencies.
- forecasting expected opex efficiency and productivity change.

These are considered separately below.

Review of base year opex

Details about reviewing base year opex are currently considered in chapter 5. Essentially, we prefer to rely on the revealed cost base-step-trend forecasting approach that we currently apply. We propose adjusting the revealed cost base year when:

- an NSP appears materially inefficient in comparison to its peers
- in tandem with incentive schemes, the revealed cost forecast would yield an outcome that is not consistent with the opex criteria.

Economic benchmarking is one of a number of tools that we intend to apply to see if a NSP appears materially inefficient compared with its peers. Our likely near term approach is to use an econometric model to forecast opex requirements. We will use a regression of historical opex costs against outputs, input prices and environmental factors, based on an approach Economic Insights developed for SP AusNet's gas distribution network.²⁸¹

The econometric technique assumes that, in the short term, capital inputs are exogenous to management control. Hence, we will include the quantity of capital in the regression as a control variable.

A regression is directly able to incorporate operating environment factors that may affect a NSP's costs. Further, statistical testing can be applied to measure the explanatory power of the technique and the sensitivity of benchmarking results.

In workshops one NSP commented that it would like to see flexible cost functions used to forecast opex.²⁸² We consider that a flexible cost function would be preferred, but a more restrictive function may be found more appropriate by statistical testing. The appropriate cost function will differ depending on the quantity and quality of data available.

Review of expected opex efficiency and productivity change

We consider that using the econometric technique to forecast the rate of change in opex is preferable to macro-based modelling for adjustments to labour cost escalation. The macro-based forecast is an approach that we used previously to forecast the rate of change in opex. Under this approach macro-economic and sector-level data are used in the forecasting model to forecast labour cost escalation. In some instances this has also included an adjustment for expected labour productivity change.

The econometric cost modelling offers a more coherent approach to forecasting opex escalation as it explicitly models input price changes, output growth and efficiency and productivity gains as cost drivers. By jointly accounting for the change in these factors, it mitigates the risk of double counting or

²⁸¹ Economic Insights, Econometric estimates of the Victorian gas distribution businesses' efficiency and future productivity growth, Report prepared for SP AusNet, 28 March 2012.

²⁸² AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 2.

inappropriately accommodating the drivers of the rate of change in opex. Further, the econometric approach can provide more firm-specific forecasts (hence accounts for the individual circumstances of NSPs) whereas the macro modelling approach assumes sector-level labour price changes and/or labour productivity change can be applied directly to a NSP.

NSPs were concerned the economic benchmarking techniques will not necessarily represent the cost drivers that affect output growth for opex forecasting. They stated the quantity of capital is a prime driver of opex.²⁸³ We consider that the outputs of a NSP are the same regardless of whether partial productivity or total productivity is being measured. The scale of a network should be measured in terms of its outputs. However, other relevant explanatory variables will be included in the regression to account for operating environment factors. Further, the quantity of capital is being included as a control variable.

Workshop participants submitted there is no one productivity growth factor for a NSP. Instead, different cost categories can have different productivity changes. Corporate overhead can have greater economies of scale than other cost categories, for example.²⁸⁴ We note a NSP may have multiple sources of productivity change and their contribution to the overall productivity change may differ across cost categories. We consider that an econometric technique is an appropriate method for an overall forecast of these productivity gains. It has the ability to capture the relationships between inputs, outputs and environmental factors at the aggregate level. Further, it may mitigate the need for an intrusive review into sources of potential efficiency gains.

Other matters raised in submissions

Submissions also raised several other issues about applying economic benchmarking. These are considered below.

Differences between transmission and distribution

We anticipate the application of economic benchmarking techniques will differ for transmission and distribution networks because their activities and outputs differ. Further, there are fewer transmission networks, which means there will be less data for our economic benchmarking analysis. In turn, this may limit the techniques we can apply.

A number of submissions commented on the differences between transmission and distribution networks. SP AusNet supported applying economic benchmarking to distribution,²⁸⁵ but commented on the difficulty of applying it to transmission:

For transmission networks, TFP-based regulation cannot properly capture genuine differences in the levels of productivity of individual companies. Transmission is highly capital intensive, with investment in large-scale long-lived assets occurring in lumpy increments. These characteristics can distort measures of productivity for extended periods. Furthermore, 'output' is notoriously difficult to define with respect to electricity transmission, and therefore it is very difficult to be confident that measures of productivity will reflect actual performance. Given these considerations and the inherent characteristics of the electricity transmission sector, application of TFP regulation would create significant uncertainty for the sector.²⁸⁶

²⁸³ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 2.

²⁸⁴ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 3.

²⁸⁵ SP AusNet, *Expenditure Forecast Assessment Guidelines- Issues Paper*, 15 March 2013, p. 2.

²⁸⁶ SP AusNet, *Submission on AEMC's Review of Total Factor Productivity Preliminary Findings Paper*, 22 February 2010.

Further, Grid Australia noted the following specific challenges in applying economic benchmarking to transmission:

- inherent challenges— the lumpy nature of investment, the difficulty in measuring the full suite of outputs that TNSPs provide, and the substantial dependence of efficient cost on a suite of environmental factors
- challenges specific to Australian TNSPs— material differences across TNSPs that largely they cannot influence, and the small number of TNSPs that limits the ability to control statistically for ‘environmental factors’
- limited experience— there is very limited experience of applying benchmarking to TNSPs by other regulators or in academic studies, meaning there is little guidance on how to do it in Australia.²⁸⁷

We note Grid Australia’s and SP AusNet’s concerns and have consulted on these matters as part of the consultation on economic benchmarking. Despite these concerns, we consider there is merit in economic benchmarking for transmission networks. Until we attempt economic benchmarking, we will not have a definitive view on its applicability to TNSPs.

TNSPs should be expected to improve their productivity over time. Expenditure forecasts should be expected to be at least as efficient as historical expenditures. So, despite the difficulties of cross sectional comparisons of economic benchmarking results for TNSPs, the measurement of their productivity over time will be relevant.

The cost of capital

Workshop participants discussed the sensitivity of economic benchmarking to the WACC. Specifically, they considered the efficiency of expenditure forecasts may be sensitive to the cost of capital used in the economic benchmarking analysis.²⁸⁸ We are separately consulting on the WACC.

Economic Insights commented on the WACC to be used for economic benchmarking:

For economic benchmarking purposes the annual user cost of capital should ideally use an exogenous or ex-ante approach as discussed in the preceding subsection. This is because producers base their production and investment decisions on the price of using capital they expect to prevail during the year ahead rather than being able to base them on the price of using capital actually realised in the year ahead (as would be only known with the benefit of perfect foresight). This points to using the WACC NSPs expect to prevail at the start of each year rather than the actual realised WACC for that year.

Because NSPs operate under regulation which specifies a forecast WACC for regulatory periods of 5 years, it would appear reasonable to use the regulated WACC for all years in the relevant regulatory period for each NSP. But, because the regulatory periods do not coincide for all NSPs and because the regulatory WACC tends to change over time, this would lead to NSPs all having somewhat different WACCs for economic benchmarking purposes. While this may reflect reality, it has the downside of making it more difficult to compare like-with-like when making efficiency comparisons because capital is receiving different weights. It also makes it difficult to compare total costs across NSPs because they will be influenced by the use of different regulatory WACCs for each NSP.

A pragmatic solution to this in the initial round of economic benchmarking may be to use a common WACC across all NSPs when assessing expenditure forecasts and, by extension, for historical comparisons of

²⁸⁷ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 18 March 2013, p. 3.

²⁸⁸ AER, 'Meeting summary - NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream - Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013 AER, 'Meeting summary – economic benchmarking applications ', *Workshop 17: Economic benchmarking techniques work-stream - Prescription in the EFA guideline, potential application techniques (Transmission & Distribution)*, 6 June 2013,, pp. 2–3.

efficiency performance. A candidate WACC would be the WACC used in the most recent NSP regulatory determination which could be assumed to apply to all NSPs for both the forecast and historical period.

Sensitivity analyses should be undertaken of the effect of using:

- a common regulatory WACC across all NSPs
- the WACC from the most recent regulatory determination for each NSP for all years for that NSP
- the forecast WACCs for each regulatory period for each NSP, and
- the realised (regulatory) WACC for each year.²⁸⁹

We consider the WACC for economic benchmarking should reflect the relevant WACC for the period under consideration. However, we note the practical issues involved in measuring this WACC. Therefore, we consider Economic Insights' proposal to use a common WACC across NSPs for assessing expenditure forecasts would be appropriate. We also consider it appropriate to use a common WACC across NSPs to measure historical efficiencies. However, we do not necessarily agree the forecast WACC and historical WACC should be the same.

We note the choice of WACC could potentially affect the outcomes of economic benchmarking analysis. However, the significance of this concern is not yet known. As recommended by Economic Insights, we intend to conduct sensitivity analysis of the appropriate WACC for economic benchmarking.

The ENA raised a concern about us seeking to implement economic benchmarking techniques which looked at NSP performance relative to frontier efficient firms, rather than the average firm performance:

The economic benchmarking techniques the AER appears to favour most may not be consistent with the National Electricity Rules (NER) intent on incentive regulation. The AER expresses a preference for economic benchmarking to assess efficiency, including the efficiency of expenditure allowances against a 'frontier' efficient firm. However, the regulatory WACC required by the NER is one that is consistent with average performance—with higher performing firms expected to earn higher rates of return.²⁹⁰

While we are aware that there are different approaches taken to estimate particular WACC parameters, this does not mean that this approach should be adopted in setting expenditure allowances. By setting expenditure allowances that account, to some extent, for frontier productivity performance and at the same time incentivising NSPs to better their historical performance will lead to continual improvement in productivity performance and shifting out the frontier over time. Such an approach is consistent with expenditure criteria, and promotes the NEO.

A.2.2 Economic benchmarking data requirements

Our holistic approach to economic benchmarking requires a holistic approach to data collection. We will collect a broad range of data so we can apply a range of economic benchmarking techniques, and conduct sensitivity analysis on possible economic benchmarking model specifications. A broad range of data, if publicly available, will also allow NSPs and other interested parties to undertake this process themselves. We will also require back casting to create time series of data, so we can consider NSPs' productivity performance over time.

²⁸⁹ Economic Insights, *Economic Benchmarking of Electricity Network Service Providers*, 25 June 2013, p.66.

²⁹⁰ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p.5.

Economic benchmarking techniques measure NSPs' efficiency by measuring their ability to convert inputs into outputs. Economic benchmarking analysis requires data on NSPs' inputs, outputs and environmental variables. Outputs are the total goods and services a firm delivers. Inputs are the resources a firm uses to deliver outputs to its customers. Environmental variables affect a firm's ability to convert inputs into outputs and are outside the firm management's control.

Scope of services

We consider services classified under prescribed transmission services to be the appropriate scope of services for comparisons between TNSPs. We consider services are treated consistently, as defined in chapter 10 of the NER.

For DNSPs, there are differences between standard control services, negotiated services and alternative control services across jurisdictions, so we consider the DNSPs' 'poles and wires' activities classified under network services to be the appropriate service to measure for economic benchmarking. Proper economic benchmarking requires a common coverage of services, and we prefer a narrow coverage because it imposes lighter information requirements.

In our recent DNSP determinations we grouped distribution services into the following seven service groups:²⁹¹

- network services
- connection services
- metering services
- public lighting services
- fee-based services
- quoted services
- unregulated services.

We consider Economic Insights' recommendation—a narrow service coverage that only includes network services—to be appropriate.²⁹² Network services are classified as standard control services across all states and territories; other services, such as connection services, are classified differently. Although a wider service coverage may better model a DNSP's overall functions, it may be impractical to include services that are not consistently classified as a standard control service. Customer funded connections, for example, are classified as unregulated in New South Wales, as an alternative control service in Queensland and as a negotiated service in South Australia.²⁹³

Our narrow service coverage will require DNSPs to exclude any non-network services classified under standard control services.

²⁹¹ AER, Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015, 29 October 2010; AER, Final Decision: South Australia electricity distribution network service provider: Distribution determination 2010–11 to 2014–15, 6 May 2010; AER, Final Decision: Queensland electricity distribution network service providers: distribution determination 2010–11 to 2014–15, 6 May 2010.

²⁹² Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 30.

²⁹³ AER, Matters relevant to the framework and approach: ACT and New South Wales DNSPs 2014–19: Classification of electricity distribution services in the ACT and New South Wales, consultation paper, December 2011, p. 13.

Network complexity, system boundaries and network planning

We consider the choice of input variables and sensitivity analysis can account for differences in NSPs' system structures between jurisdictions. Material differences between jurisdictions should be accounted for so all DNSPs are compared in the same manner. Similarly, all TNSPs should be compared in the same manner.

Stakeholders used workshops and submissions to identify the following differences in network complexity and system boundaries:

- The boundary between TNSPs and DNSPs differs across jurisdictions. DNSPs in Tasmania and Victoria receive their power at a lower voltage than do DNSPs in New South Wales and Queensland, for example. This may result in a simpler distribution network (and a more complicated transmission network) in Tasmania and Victoria relative to New South Wales and Queensland.²⁹⁴
- DNSPs in Victoria conduct transmission connection point planning, unlike in other jurisdictions.
- AEMO is responsible for planning and procuring all shared transmission network augmentations in Victoria.

Economic Insights considers the difference in network complexity can be accounted for by disaggregating transformer inputs to identify where there are high voltage transformation steps. This, combined with disaggregating line lengths in voltage classes, should allow for appropriate sensitivity analysis.²⁹⁵

We consider this an appropriate approach to network complexity. It also allows sensitivity analysis on the total cost of DNSPs and TNSPs combined in each jurisdiction.

CitiPower, Powercor and SA Power Networks considered that the costs related to transmission connection point planning are material and that they should not be included when calculating total operating costs for economic benchmarking.²⁹⁶

We consider if there is evidence to suggest costs associated with transmission connection point planning are material, then these costs should not be included in the Victorian DNSPs' total operating costs if these costs are not borne by DNSPs in other jurisdictions. The materiality of these differences in costs may be compared across NSPs as a part of our sensitivity analysis.

For AEMO and SP AusNet, where some planning is undertaken by AEMO, we will consider these costs in aggregate to consistently compare costs between TNSPs.

Economic benchmarking variables selection criteria

In the issues paper, we set out a framework for selecting economic benchmarking variables because the literature was not entirely consistent about which variables are relevant.²⁹⁷ The sections below set out our selection criteria for outputs, inputs and environmental variables.

²⁹⁴ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 52; AER, Summary of working group meeting, Meeting no. 14, 7 May 2013, p. 2.

²⁹⁵ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 52.

²⁹⁶ CitiPower, Powercor Australia and SA Power Networks, *Submission to AER on economic benchmarking of electricity distribution service providers*, 30 May 2013, p. 8.

Principles for selecting outputs

We previously outlined our criteria for selecting output variables in the issues paper and we have not revised these selection criteria.²⁹⁸ Feedback from submissions and in workshops suggested stakeholders agreed the selection criteria appear to be reasonable.

Table A.4 Criteria for selecting output variables

Criteria	Justification
The output aligns with the NEL and NER objectives	<p>The NEL and NER provide a framework for reviewing NSP expenditure. The expenditure objectives are to achieve the following:</p> <ul style="list-style-type: none"> - meet or manage the expected demand for standard control services over that period - comply with all applicable regulatory obligations or requirements associated with the provision of standard control services - maintain the quality, reliability and security of supply of standard control services - maintain the reliability, safety and security of the distribution/transmission system through the supply of standard control services.²⁹⁹ <p>Economic benchmarking outputs should align with the deliverables in the expenditure objectives to assist us in reviewing whether expenditure forecasts reflect efficient costs.</p>
The output reflects services provided to customers	<p>It is important to distinguish between the goods or services that a firm provides from the activities that it undertakes.</p> <p>Outputs should reflect the services that are provided to customers. Otherwise, economic benchmarking may incentivise activities customers do not value. Replacing a substation does not represent a service directly provided to a customer, for example. If replacing a substation was considered an output, an NSP may replace substations to appear more efficient, rather than undertake activities that will more directly deliver services for customers.</p>
The output is significant	<p>There are many output variables for NSPs. For economic benchmarking, the variables must be significant either in terms of their impact on customers or on costs of NSPs. This is consistent with the high level nature of economic benchmarking.</p>

Principles for selecting inputs

We previously outlined two criteria for selecting input variables in the issues paper. That is, input variables should be:

- reflective of the production function
- consistent with the NEL and the NER.³⁰⁰

Stakeholders generally considered our selection criteria to be appropriate. However, stakeholders did provide some views. In particular, SP AusNet questioned if it is appropriate to include a criterion that

²⁹⁷ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 60.

²⁹⁸ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 74.

²⁹⁹ NER, cl. 6.5.6(a), 6.5.7(a), 6A.6.6(a) and 6A.6.7(a).

³⁰⁰ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 62.

the inputs should be 'exhaustive'.³⁰¹ In addition, Aurora considered that modelling a business in its entirety is unnecessarily complex.³⁰²

We have also changed our justification for the 'reflective of production function' selection criterion to clarify that the input specification should include all subcomponents of inputs (labour, capital, material and other inputs) and avoid double counting them. In addition, following the feedback from submissions and the workshops, Economic Insights recommended expanding the selection criteria for inputs.³⁰³

As well as the two selection criteria identified in the issues paper, Economic Insights recommended two additional criteria to capture the annual capital service flow of NSP assets (based on the NSP's RAB and to ensure input variables comply with the NEL and the NER.

Table A.5 sets out the criteria we consider relevant for input measures for the economic benchmarking techniques.

Table A.5 Criteria for selecting input variables

Criteria	Justification
Reflective of the production function	Inputs should reflect all the factors and resources an NSP uses to produce outputs modelled. The inputs should capture all the inputs an NSP uses in producing its output and be mutually exclusive so the factors of production are not double counted or omitted.
Measures of capital input quantities accurately reflect the quantity of annual capital service flow of assets the NSP employs	This ensures the depreciation profile used in forming the capital is consistent with the physical network asset depreciation characteristics. ³⁰⁴
Capital user costs are based on the NSP's RAB	The annual user cost can be calculated differently. It is desirable for economic benchmarking analysis to use capital costs calculated based on the same methodology as the corresponding building blocks components. Otherwise the annual user cost of capital could be calculated differently, which may yield considerably different efficiency results over short periods of time during an asset's life.
Consistency with the NEL and NER	The NEL and NER provide a framework for reviewing NSP expenditure. The input variables for economic benchmarking should enable us to measure and assess the relative productivity efficiency of NSPs in the National Electricity Market (NEM).

Principles for selecting environmental variables

There are many environmental factors outside of a NSP's control that may affect the NSP's costs, and economic benchmarking may need to account for these. However, as with the outputs and inputs, it is important to prioritise or aggregate relevant environmental variables.

³⁰¹ SP AusNet, *Expenditure Forecast Assessment Guidelines— Issues Paper*, 15 March 2013, p. 18.

³⁰² Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 12.

³⁰³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 53.

³⁰⁴ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 53.

Our selection criteria for environmental variables will assist us in choosing only the most material differences between NSPs' operating circumstances rather than controlling for all potential differences which may not significantly impact the efficiency of an NSP.

SP AusNet submitted it is not clear if it is necessary to adopt the primary driver of costs where there is a correlation with another environmental variable. In particular, it is unclear how to identify the primary cost driver without conducting some form of benchmarking or econometric analysis.³⁰⁵

Table A.6 Criteria for selecting environmental variables

Criteria	Justification
The variable must have a material impact	There are numerous factors that may influence an NSP's ability to convert inputs into outputs. Only those with a material impact on costs should be selected.
The variable must be exogenous to the NSP's control	We consider environmental variables are exogenous to an NSP's control. Where variables are endogenous, investment incentives may not align with desired outcomes for customers. Further, using endogenous variables may mask inefficient investment or expenditure.
The variable must be a primary driver of the NSP's costs	Many factors that could affect the performance might be correlated because they have the same driver. Line length and customer density may be negatively correlated, for example. If there is correlation, the primary driver of costs should be selected. Higher line length might reflect a lower customer density, so perhaps customer density should be selected as the environmental variable because it may be considered to more directly influence costs.

We agree econometric analysis can be used to test if there is a statistical relationship between the environmental variable and the NSPs efficiency score.

Further, we agree econometric analysis will be required to identify any correlations between variables included in our model specifications. Multicollinearity occurs where there is perfect correlation between variables. If the variables in a regression are perfectly correlated it is not possible to separate the individual effects of the components in a regression.³⁰⁶

If there are environmental variables that are correlated, including only the primary cost driver will limit the issue of multicollinearity in our econometric estimates. Using multiple environmental variables will be a part of our sensitivity analysis. Multicollinearity may not be an issue if the analysis is to predict efficiency performance. It is only relevant if accurate estimates of the individual impact of environmental variables are required.

Outputs

Outputs are generally considered to be the total of the goods and services a business delivers. However, these can be difficult to define for NSPs because they deliver services that are less tangible

³⁰⁵ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 23.

³⁰⁶ W Greene, *Econometric analysis*, 4th edn, Prentice Hall, New Jersey, 1999, p. 256.

or homogeneous than the outputs of other industries (such as manufacturing).³⁰⁷ The services provided by NSPs have a number of dimensions. The variables used to model NSPs' outputs consider these dimensions, including both the quality and quantity of services.

Given the difficulties associated with defining NSPs' outputs, economic benchmarking studies have adopted varying output specifications.³⁰⁸ Further, multiple measures can be used to measure individual aspects of network services. Because there is no singular output specification used for economic benchmarking, we established principles and criteria for selecting NSP output variables. We consider the output of NSPs is the provision of required system capacity that takes into account the trade-off between increased reliability and the value that customers place on additional reliability. Each output variable examined in the sections below is discussed in relation to this definition of NSP output and the output selection criteria.

Billed versus functional outputs

We consider a functional outputs specification, rather than a billed outputs specification, is more appropriate for measuring NSPs' outputs under building block regulation. However, we consider data should be obtained for both functional and billed outputs to facilitate future sensitivity analysis.

Outputs can be measured on an 'as billed' basis or on a 'functional' basis. A significant proportion of a DNSP's revenue is charged through energy delivered ('as billed' basis); a NSP's costs, however, are focused on providing reliability to customers ('functional' basis).

Stakeholders attending workshops preferred the functional outputs specification because there is little causal relationship between billed outputs (such as energy delivered) and NSPs' costs.

Economic Insights noted that under building block regulation there is typically no direct link between the revenue requirement the DNSP is allowed by the regulator and how the DNSP structures its prices. The regulator sets the revenue requirement necessary to meet the objectives in the NER. However, the DNSP sets its prices based on pricing principles, which is a separate process to setting the revenue requirement.³⁰⁹

We support Economic Insights' recommendation to collect data that would support both functional and billed output specifications so we can undertake sensitivity analysis in the future.³¹⁰ It will also allow for comparisons with other economic benchmarking studies that use billed and/or functional outputs.

Output weights

Output weights are required to determine the proportion each output variable contributes to total output in terms of quantity or cost. We prefer an econometric cost function to determine output weights because, over time, more complex cost functions can be developed when more data are available.

Economic Insights suggested other approaches, including using weights from previous studies and obtaining estimates from other DNSPs.³¹¹ However, these approaches have limitations. First, using weights from previous cost function studies will limit our choice of output variables to the same

³⁰⁷ Hattori T, Jamasb T and Pollitt MG, *Relative performance of UK and Japanese electricity distribution performance 1985–1998: lessons for incentive regulation*, [Cambridge Working Papers in Economics](#) 0212, Faculty of Economics, University of Cambridge, 2002, p. 4.

³⁰⁸ ACCC/AER, *Benchmarking opex and capex in energy networks*, Working paper no. 6, May 2012, pp. 53–5.

³⁰⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 6.

³¹⁰ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 6.

³¹¹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 22.

outputs used in the previous studies. Second, obtaining estimates of the relative cost of producing each output from the DNSPs will not be as objective as estimating a cost function. Nevertheless, information from previous cost function studies and from the DNSPs themselves will be useful for sensitivity analysis and as a sanity check for the econometric method.

Workshop participants considered using revenue shares to determine output weights would not represent the value of the output to customers. United Energy noted the absence of prices that reflect costs necessitates a move away from simple revenue shares as the basis for weighting the outputs.³¹²

DNSP outputs

We consider it important to measure functional outputs that drive DNSPs' costs, but to conduct sensitivity analysis it is important to also measure outputs that customers pay for. That is, it is appropriate to obtain information on a DNSP's billed outputs (the outputs that represent what a DNSP charges its customers for) and its functional outputs (the outputs that represent how a DNSP's revenue requirement was determined under the building block model).

The sections below discuss the most material outputs Economic Insights raised in consultation with stakeholders. We assess each output in relation to the selection criteria and feedback from stakeholders.

Customer numbers

We consider customer numbers meets all the selection criteria and it should be included as an output for DNSPs. Hence it is included in our preferred model specification. The issues paper stated the reasons for using customer numbers:³¹³

- There is a correlation between the number of customers and many distribution activities (relating to metering services, customer connections, customer calls, etc).³¹⁴
- Network firms have a legal obligation to connect all customers within their designated area, and the firms have to maintain the power lines in operation even if they are only used seasonally.³¹⁵

The scope of services covered in our economic benchmarking diminishes the level of correlation between customer numbers and distribution services because we exclude all non-network services (such as customer funded connections). However, DNSPs are legally obliged to connect customers and to maintain the power lines, so the number of customers is still a material output.

In the workshops there was general agreement that customer numbers should be included as an output. Further, Economic Insights noted customer numbers have been used as a proxy for the quantity of the functions required by DNSPs to provide access regardless of the energy delivered. The functions required by DNSPs include metering services, customer connections, customer calls and connection related infrastructure.

³¹² United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper*, Australian Energy Regulator, 19 March 2013, p. 12.

³¹³ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 83.

³¹⁴ Coelli T, Gautier A, Perelman S and Saplacan-Pop R, 2010, *Estimating the cost of improving quality in electricity distribution: A parametric distance function approach*, Paper presented at Lunch Seminar in Energy, Environmental and Resource Economics Spring 2011, Swiss Federal Institute of Technology, Zurich, p. 7.

³¹⁵ Kuosmanen T, 'Cost efficiency analysis of electricity distribution networks: Application of the StoNED method in the Finnish regulatory model', April 2011, p. 10.

Economic Insights considered DNSPs are obliged to connect customers, so customer numbers reflect services directly provided to the customer and can be a significant part of DNSP costs which score well against our output selection criteria.³¹⁶ SP AusNet also supported including the number of customers served and it suggested distinguishing between the types of customers.³¹⁷ By contrast, Aurora did not think customer numbers should be used as an output. Rather, it meets the criteria of an environmental variable.³¹⁸

Economic Insights distinguishes outputs from environmental variables thus: outputs reflect services directly provided to customers, whereas environmental variables do not.³¹⁹ We consider this is an appropriate distinction and that customers should be included as an output. We also agree with SP AusNet's suggestion to distinguish between the types of customers if data are available.

Economic Insights also recommended customers numbers disaggregated by customer type as an alternative output specification that does not use either peak demand or system capacity. Although this specification does not measure required system capacity, the specification can potentially measure a DNSP's ability to provide adequate capacity to its customers.³²⁰

System capacity and peak demand

Ideally, our preferred model specification would capture required system capacity as an output because this is the level of capacity required by customers to meet their needs. However, this is not directly observable, so system capacity or peak demand can serve as a proxy. Initially, we will use system capacity until an adequate data series of peak demand that is less volatile can be developed. As an output variable, both measures have strengths and weaknesses that warrant further research.

We received several submissions on these output measures. Some workshop participants preferred peak demand over system capacity. They considered peak demand better measured the load a DNSP must be able to accommodate and is a more appropriate proxy for required system capacity. Further, workshop participants considered non-coincident peak demand better measured network output than did coincident peak demand.³²¹

Jemena considered peak demand an undesirable proxy for system capacity because in practice, having just enough capacity to meet peak demand is not achievable and is not dynamically efficient. When additional capacity is required, it is more efficient to install 'excess' capacity to meet forecast demand growth for a period than it is to expand in frequent small increments. Jemena suggested system capacity is a more significant driver of inputs requirements and costs.³²²

By contrast, SP AusNet considered forecast peak demand, as approved in regulatory determinations, is what businesses are required to provide sufficient capacity. As such, it drives investment planning and decision-making.³²³ Similarly, the MEU noted peak demand by each connection is the prime driver of what the network requires to provide, subject to appropriate recognition of diversity.³²⁴

³¹⁶ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 9.

³¹⁷ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 21

³¹⁸ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 15.

³¹⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 6.

³²⁰ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 32.

³²¹ AER, 'Meeting summary - DNSP outputs & operating environment factors ', *Workshop 5: Economic benchmarking techniques work-stream - Network outputs (Distribution)*, 13 March 2013, p. 3.

³²² Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 8.

³²³ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 22.

³²⁴ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 30.

CitiPower considered system capacity should only be included if it is scaled to account for network utilisation. Failure to account for utilisation would create incentives for building inefficient levels of excess capacity. Further, CitiPower considered forecast peak demand to be an appropriate alternative for system capacity because it accounts for the probability of peak demand events occurring that the network must be ready to accommodate to ensure reliable supply.³²⁵

Economic Insights considers actual peak demand to be a poor indicator of the load capacity a DNSP is required to provide and, given its volatility, using actual peak demand would likely lead to inappropriate volatility in efficiency results.

It also considers forecast non-coincident peak demand from the most recent regulatory determinations may provide an indication of the loads the DNSP was expected to be able to meet because they were built into the building blocks revenue requirements. However, there are limitations. Once a building block allowance is set, DNSPs are expected to respond to the incentive to be efficient and this may include responding to lower than forecast demand and/or revised forecast demand. It may also provide an incentive for DNSPs to over-inflate forecasts in future reviews.

We consider non-coincident peak demand better reflects the capacity DNSPs build to, than does coincident peak demand. Coincident peak demand measures the peak demand of the overall network rather than the aggregate peak demand of individual assets. It is unlikely coincident peak demand will reflect the actual capacity required for a given asset. However, peak demands in general do not distinguish between the amount of lines required by two DNSPs who have similar peak demands but different service areas (for example, one is rural and the other is urban). With lower customer density, the rural DNSP may appear less efficient unless the greater line length requirement is accounted for. In such cases, line length could be incorporated as an environmental factor.

According to Economic Insights, including system capacity as an output provides a means of recognising lines as well as transformer requirements and, in the short term, system capacity is preferable to smoothed peak demand. It also recommended investigating including smoothed peak demand (with adjustments for customer density differences included as an operating environmental factor), once sufficient data observations are available.³²⁶

United Energy submitted that economic decisions are based on probabilities such as the probability of failure, and that the use of peak demand or system capacity is not probabilistic in nature. Instead, United Energy recommended adopting the 'value of energy at risk' as an output which aligns with economic decisions such as whether or not to augment. However, it was also noted that the calculations to obtain this measure are complicated by the many combinations and permutations of energy flows and would require further research.³²⁷

We note that there is merit to aligning the outputs to the economic decision making process as far as possible. However, the difficulties highlighted by United Energy to calculate such a measure appear to make it unfeasible to utilise such a measure—particularly in light of NSPs already highlighting difficulties in providing back cast system capacity data.

³²⁵ CitiPower, Powercor Australia and SA Power Networks, *Joint submission to AER on economic benchmarking of electricity distribution service providers*, 30 May 2013, p. 4.

³²⁶ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 14.

³²⁷ United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper*, Australian Energy Regulator, 19 March 2013, p. 11.

CitiPower, Powercor and SA Power Networks submitted a methodology to account for utilisation that could be measured as the ratio of non-coincident peak demand divided by system capacity attributable to the zone substation.³²⁸

We consider that system capacity adjusted for utilisation may be appropriate in the short term and that the ratio method warrants further investigation. The level of utilisation will not be a variable in the preferred model specification, but sensitivity analysis will be adopted to account for utilisation and peak demand.

In the long term, we consider some smoothed measure of peak demand should be adopted, in conjunction with an environmental variable that accounts for line lengths and densities. We also consider a 'ratcheted' peak demand (where the peak demand of each asset is summed over a five year period to obtain a rolling peak demand series) could be used. This would require 14 years of data to get the 10 data points necessary for more robust economic benchmarking.

Reliability

We consider reliability satisfies all three output selection criteria. Improving reliability is a significant driver of DNSP costs, it is valued by customers, and it is reflected in the capital expenditure (capex) and opex objectives.³²⁹ We also recognise there are cost trade-offs between increasing reliability and the price consumers will have to pay for increased reliability. More research will need to be undertaken to determine the value of reliability to customers.

There was general agreement in submissions and workshops that reliability should be captured in some manner.³³⁰ However, there are some issues in how reliability can be measured for economic benchmarking. Some DNSP representatives considered there to be a lag between changes in expenditure and observed changes in reliability. This may occur when expenditure programs (which may take several years to complete) do not have a noticeable effect on reliability until all interrelated programs are complete (that is, expenditure first then changes in reliability). By contrast, other DNSP representatives indicated it may take time to identify issues in reliability and then to implement a program to remedy that issue (that is, reliability change first, then changes in expenditure).

Economic Insights recommends using current year reliability initially and then formally testing for a lag between expenditure and reliability once a longer time series is available.³³¹ In the absence of quantitative evidence, our preferred model specification does not include such a lag.

United Energy submitted that a business may be required to invest more in replacing its assets to maintain existing levels of reliability, but this also provided a broader community benefit by reducing the risk of fire starts (and that economic benchmarking may not capture this relationship). We consider broader community benefits are important, but to account for any differences in economic benchmarking we require NSPs to demonstrate that these specific obligations have a materially different impact on their efficiency compared to NSPs in other jurisdictions. We are aware that Victoria has an F-factor scheme that provides incentives for DNSPs to reduce the risk of fire starts.³³²

³²⁸ CitiPower, Powercor Australia and SA Power Networks, *Joint submission to AER on economic benchmarking of electricity distribution service providers*, 30 May 2013, p. 4.

³²⁹ NER, cl. 6.5.6(a), 6.5.7(a), 6A.6.6(a) and 6A.6.7(a).

³³⁰ SP AusNet, *Expenditure Forecast Assessment Guidelines— Issues Paper*, 15 March 2013, p. 22; Major Energy Users, *Better regulation expenditure forecast guidelines: Comments on the issues paper*, March 2013, p. 31.

³³¹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 17.

³³² AER, *F-factor scheme determinations 2012–15 for Victorian electricity distribution network service providers*, 22 December 2011.

Further, United Energy noted that economic benchmarking may also not capture differences in expenditure as a result of differences in the average age of their networks. This would occur in economic benchmarking models where the input variable is measured as a dollar value, and not in a physical quantity which is not as relevant.³³³

We agree with United Energy that the average age of the network may affect the level of inputs without a change in the outputs. We also agree that our measure of capital inputs mitigates some of this issue by only examining the level of capital flow rather than the costs. However, we will have to take this into account when assessing any expenditure forecasts. One approach would be to account for asset age as an environmental variable.

Other data requirements

As mentioned above, we consider it is necessary to collect a broader set of data to apply alternative model specifications and to undertake sensitivity analysis. Table A.7 presents alternative DNSP output specifications to our preferred DNSP output specifications. These alternative specifications largely follow the recommendations made by Economic Insights as a part of its shortlisted output specifications.³³⁴ However, our sensitivity analysis will not be limited to these alternative specifications.

Table A.7 Alternative DNSP output specifications

Quantity	Value	Price
Specification 2		
Customers (no.)	Revenue*Cost share	Value/Customers
Smoothed non-coincident peak demand (MVA)	Revenue*Cost share	Value/MVA
Interruptions (customer mins)	-1*Customer minutes*VCR per customer minute	-1*VCR per customer minute
Additional input for specification 1 and 2		
Energy delivered (GWh)	Revenue*Cost share	Value/GWh
Specification 3		
Residential customers (no.)	Revenue*Cost share	Value/Residential customers
Commercial customers (no.)	Revenue*Cost share	Value/Commercial customers
Small industrial customers (no.)	Revenue*Cost share	Value/Small industrial customers
Large industrial customers (no.)	Revenue*Cost share	Value/Large industrial customers
Interruptions (Customer minutes)	-1*customer minutes*VCR per customer minute	-1*VCR per customer minute

Abbreviations: VCR – value of customer reliability, MVA – megavolt amperes, GWh – gigawatt hour.
Source: Economic Insights and AER analysis.

³³³ United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper*, Australian Energy Regulator, 19 March 2013, p. 12.
³³⁴ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 31.

Specification two is similar to our preferred output specification, except system capacity has been replaced by peak demand and energy delivered has been included as an output. Including energy delivered is not limited to specification two; sensitivity analysis will also incorporate this output in our preferred DNSP output specification.

The third specification could potentially measure a DNSP's ability to provide adequate capacity to meet customer needs. This specification is not affected by the issues associated with using system capacity of peak demand as an output. However, there is no direct relationship between the outputs and required system capacity. The section below discusses additional data required for our alternative model specifications and sensitivity analysis.

Energy delivered

We consider energy delivered should not be included in our preferred model specification, but data on energy delivered should still be obtained for sensitivity analysis. Energy delivered is not a material driver of DNSPs' costs and is likely to receive a small output weighting.

Energy delivered has been used as a variable in other economic benchmarking studies. However, Turvey suggests DNSPs act passively in distributing energy along their lines and cables and through their switchgear and transformers, so the amount distributed is not decided by the DNSP. Further, in the short term, a load alteration will not affect the size of the network and will only trivially affect operation and maintenance costs.³³⁵

Participants had mixed views. SP AusNet considered energy delivered should not be dismissed but maybe a small weighting should be applied.³³⁶ By contrast, Aurora submitted energy delivered is not relevant for planning or operation. However, it suggested using energy delivered to calculate energy not delivered as a reliability indicator.³³⁷ Similarly, United Energy considered changes in energy delivered do not drive changes in costs, so throughput should not be considered a significant output.³³⁸

Economic Insights noted energy delivered can be used as a proxy for system capacity. It also noted energy delivered directly reflects what customers consume, the data are relatively robust and it is included in nearly all previous economic benchmarking studies. For these reasons, Economic Insights recommended including energy delivered as an output.³³⁹

We consider energy delivered satisfies the criteria that the output reflects services to customers. However, peak demand or system capacity has more influence on the expenditure objectives than energy delivered. Consequently, energy delivered may also not significantly affect a DNSP's costs, relative to peak demand and system capacity. To limit the number of variables in our preferred output specification (which will also alleviate our degrees of freedom concerns), we consider the preferred model specifications should include only the most significant variables. Energy delivered does not satisfy this requirement. It could be included in sensitivity analysis (given its common use in other economic benchmarking studies).

³³⁵ Turvey R, 'On network efficiency comparisons: electricity distribution', *Utilities Policy*, Vol. 14(2), 2006, p. 105.

³³⁶ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 22.

³³⁷ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 16.

³³⁸ United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper*, Australian Energy Regulator, 19 March 2013, p. 10.

³³⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 9

Revenue

We consider revenue data may be limited in providing output weights. Similarly, stakeholders did not consider a billed outputs specification to be appropriate. They also argued there was no link between revenue and functional outputs. However, it could still be used in sensitivity analysis and to examine the link between revenue and billed outputs (such as customers and throughput). This is because customers are included in our preferred model specification for DNSPs and energy delivered is included in our alternative model specifications for both DNSPs and TNSPs.

We consider revenue data are not an onerous data requirement. We already receive aggregated annual revenue and disaggregating revenue into customer types and chargeable quantity is consistent with the disaggregation required for customer and energy delivered data.

System security, electricity quality and safety

We consider network security, electricity quality and safety should not be included in our economic benchmarking analysis until a robust measure is available for these variables.

Some stakeholders, such as CitiPower, Powercor and SA Power Networks, considered quality of supply should be included in economic benchmarking but noted the data limitations. They also noted quality of supply is expected to increase in Victoria with the introduction of advanced metering infrastructure meters.³⁴⁰

We consider reliability, not system security, better reflects the quality of services provided to customers. System security is also difficult to quantify for economic benchmarking.³⁴¹

We agree with Economic Insight's consideration that electricity quality and safety are important, but that they should not be included as an output variable. Safety and quality standards are a basic requirement of DNSP operation and are unlikely to be substantially different across DNSPs. There is also no single overall summary measure for quality and safety.³⁴²

TNSP outputs

TNSP outputs are broadly similar to DNSP outputs, but there are differences between the two network types. This section considers TNSP specific issues.

Entry and exit point numbers

We consider it appropriate to include entry and exit point numbers as an output variable in our preferred model specification. It is similar to using customer numbers for DNSPs. TNSPs charge generators and distribution networks for a connection point. They also provide activities such as metering services (regardless of the level of energy delivered) and they must maintain the quality, reliability and security of the electricity supply.

Economic Insights argued entry and exit points are a proxy for the activities TNSPs provide at connection points, and we support this reasoning.³⁴³ However, we acknowledge Economic Insights' observation that entry and exit point numbers meet the first and third selection criteria, but do not necessarily reflect services provided to customers.

³⁴⁰ CitiPower, Powercor Australia and SA Power Networks, *Joint submission to AER on economic benchmarking of electricity distribution service providers*, 30 May 2013, p. 5.

³⁴¹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 21.

³⁴² Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 22.

³⁴³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 36.

Like DNSP revenue, we will require TNSPs to provide revenue disaggregated by chargeable quantity, using the same approach as disaggregating the number of entry and exit points. This will be used for sensitivity analysis.

Network capacity, peak demand and energy delivered

We consider it appropriate to include network capacity in our preferred model specification and use peak demand as an alternative output specification. We will also use energy delivered for sensitivity analysis, which is consistent with our approach for DNSPs.

Some workshop participants noted capacity estimates may not be comparable across jurisdictions. Capacity arrangements must comply with the NER (which require industry best practice) and state requirements (which may impose different environmental and planning requirements across jurisdictions). Other participants argued consumers want their peak demand to be met, so peak demand may be a better measure.³⁴⁴

Grid Australia did not consider energy delivered and peak demand to be outputs of a transmission network because they cannot be controlled by TNSPs. They are determined by the interaction between generators and consumers. Grid Australia considered system capacity better reflects the service provided by TNSPs. It also suggested the system capacity measure should include transformer capacity as well as line and cable capacity.³⁴⁵

According to Economic Insights, the product of TNSP line length and the sum of terminal point and directly connected end user transformer capacity is a simple measure that may not capture the complexities of TNSP functions. However, it serves as a good starting point for developing more sophisticated system capacity measures.³⁴⁶

We consider other assessment techniques, such as regulatory investment tests for transmission (RIT-T), will mitigate the incentive to overbuild system capacity.

Like DNSP revenue, we will require TNSPs to provide revenue disaggregated by chargeable quantity, using the same approach as disaggregating energy delivered. This will be used for sensitivity analysis.

Reliability

We consider reliability as an output satisfies all three selection criteria and should be included in our economic benchmarking. The number of loss of supply events and the aggregate unplanned outage duration are appropriate measures of reliability for TNSPs. We will also include an extra measure about outage frequency that is not used in the DNSP output specification. TNSPs generally have fewer outages than DNSPs, but each outage may have a larger impact than a DNSP outage.

Workshop participants acknowledged consumers are concerned with overall reliability of the network. However, they were concerned customers may not observe improved transmission reliability, relative to other issues with the wider electricity network.³⁴⁷

³⁴⁴ AER, 'Meeting summary - TNSP outputs & operating environment factors ', *Workshop 6: Economic benchmarking techniques work-stream - Network outputs (Transmission)*, 14 March 2013, p. 3.

³⁴⁵ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 18 March 2013, pp. 22–23.

³⁴⁶ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 39.

³⁴⁷ AER, 'Meeting summary - TNSP outputs & operating environment factors ', *Workshop 6: Economic benchmarking techniques work-stream - Network outputs (Transmission)*, 14 March 2013, p. 3.

Economic Insights considered secondary deliverables (relating to capacity required to deliver outputs now and in the future) should be used as a TNSP output measure. Secondary deliverables provide a lead indicator of likely future reliability.³⁴⁸ Specifically, Economic Insights proposed to include two secondary deliverables (the average circuit outage rate and the proper operation of equipment measures) when appropriate prices have been developed for these measures.³⁴⁹ Grid Australia agreed secondary deliverables such as system security are required under the NER and uphold the NEO.³⁵⁰

Alternative TNSP output specifications

Table A.8 presents alternative TNSP output specifications to our preferred output specification. These specifications were recommended as part of Economic Insights' shortlisted output specifications.³⁵¹ Our sensitivity analysis will not be limited to these alternative specifications.

Table A.8 Alternative TNSP output specifications

Quantity	Value	Price
Specification 2		
Smoothed non-coincident peak demand (MVA)	Revenue*Cost share	Value/MVA
Entry and exit points (no.)	Revenue*Cost share	Value/No
Loss of supply events (no.)	-1*Loss of supply events*Average customers affected*VCR per customer interruption	-1*Average customers affected*VCR per customer interruption
Aggregate unplanned outage duration (customer minutes)	-1*Customer minutes*VCR per customer minute	-1*VCR per customer minute
Additional input for specification 1 and 2		
Energy delivered (GWh)	Revenue*Cost share	Value/GWh

Abbreviations: VCR – value of customer reliability, MVA – megavolt amperes, GWh – gigawatt hour.
Source: Economic Insights and AER analysis.

Inputs

Previous benchmarking studies broadly agreed on NSP inputs. As with many industries, the main types of resources NSPs use to provide outputs are labour, capital, material and other inputs.³⁵²

Economic Insights noted it was important to recognise some inputs are consumed within a period. This makes their measurement relatively straightforward as the relevant quantity and cost of these inputs are the amount of those inputs purchased in that year. These non-durable inputs include labour, materials and services.³⁵³

³⁴⁸ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 33.
³⁴⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 45.
³⁵⁰ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 18 March 2013, p. 22.
³⁵¹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 45.
³⁵² ACCC/AER, *Benchmarking opex and capex in energy networks*, Working paper no.6, May 2012, p. 142.
³⁵³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 47.

Capital inputs (or durable inputs) may last several years, so the costs and quantities associated with these inputs must be attributed over the life of the input. Most benchmarking studies included an opex input category and a capital input category.

In consultation with stakeholders, Economic Insights shortlisted the following inputs specifications:

- nominal opex deflated by ABS producer price indexes (PPIs) and either the AWOTE or the WPI to obtain a quantity measure of opex, and
- one of:
 - physical proxy for capital (which includes the MVA–kms of overhead and underground lines)
 - RAB straight line depreciation proxy
 - depreciated RAB proxy.

Table A.9 outlines our preferred NSP input specification and alternative inputs.

Table A.9 NSP input specifications

Quantity	Value	Price
Preferred input specification		
Nominal opex/Weighted average price index	Opex (for prescribed services adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWWS WPI and five ABS producer price indexes
Overhead lines (MVA–kms)	Annual user cost (return of and on overhead capital)	Overhead annual user cost/MVA–kms
Underground cables (MVA–kms)	Annual user cost (return of and on underground capital)	Underground annual user cost/MVA–kms
Transformers and other (MVA)	Annual user cost (return of and on transformers and other capital)	Transformers & other annual user cost/MVA
Alternative opex inputs		
Nominal opex/Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW AWOTE and five ABS producer price indexes
Alternative capital inputs		
Nominal RAB straight–line depreciation/ ABS EGWWS CGPI	AUC (Return of and on capital)	AUC/Constant price RAB depreciation
Nominal depreciated RAB/ABS EGWWS CGPI	Revenue minus opex	(Revenue minus opex)/Constant price depreciated RAB

Abbreviations: VCR – value of customer reliability, ABS – Australian Bureau of Statistics, EGWWS – electricity, gas, water and waste services, WPI – wage price index, MVA – megavolt amperes, kVA – kilovolt amperes.

Opex inputs

We consider Economic Insight’s recommendation to adopt a common opex coverage is consistent through time and across NSPs. Opex includes all costs of operating and maintaining the network, including inspection, maintenance and repair, vegetation management, and emergency response.

Depreciation and all capital costs (including those associated with capital construction) should be excluded.³⁵⁴

The opex price index used to deflate opex should use the following price indices and weights as a starting point:

- electricity, gas, water and waste services (EGWWS) WPI—62.0 per cent
- intermediate inputs: domestic PPI—19.5 per cent
- data processing, web hosting and electronic information storage PPI—8.2 per cent
- other administrative services PPI—6.3 per cent
- legal and accounting PPI—3.0 per cent
- market research and statistical services PPI—1.0 per cent.

We note the weights use opex shares Pacific Economics Group (PEG) adopted in 2004, which were based on analysis of Victorian electricity DNSP regulatory accounts data.³⁵⁵

We consider it appropriate to use these existing weights as a starting point until analysis on DNSP and TNSP opex weights that reflect current data is available. Economic Insights recommended WPI as the appropriate opex price index (not the AWOTE) and we agree. It has some theoretical advantages over the AWOTE. We used WPI in previous decisions, given concerns about the volatility of the AWOTE.³⁵⁶ However, the difference in net regulatory effect is minimal if both measures are applied consistently in economic benchmarking.³⁵⁷ We consider it appropriate to use the AWOTE for sensitivity testing.

Capital inputs

We support Economic Insights' recommendation to use physical capital measures to proxy the annual capital service flow.³⁵⁸ That is, before allocating the cost of assets over multiple years, it is necessary to estimate the quantity of capital inputs used in the production process each year. This is also known as the flow of capital services.³⁵⁹

The quantity of capital inputs available each year will depend on the asset's physical depreciation profile. In aggregate, we consider capital inputs follow a one hoss shay depreciation profile, where the flow of capital services remains constant over time. Several participants, such as the MEU and Aurora Energy supported this assumption.³⁶⁰ By contrast, United Energy recommended undertaking further detailed analysis on the one hoss shay assumption.³⁶¹ SP AusNet argued it was false to assume an

³⁵⁴ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 54.

³⁵⁵ Pacific Economics Group (PEG) (2004), TFP Research for Victoria's Power Distribution Industry, Report prepared for the Essential Services Commission, Madison.

³⁵⁶ AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2012, pp. 57–59.

³⁵⁷ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 85.

³⁵⁸ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 85.

³⁵⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 47.

³⁶⁰ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 26; Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 13.

³⁶¹ United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper*, Australian Energy Regulator, 19 March 2013, p. 9.

asset provides a constant level of service over its lifetime, but acknowledged it may be a reasonable working assumption.³⁶²

Economic Insights considered other depreciation profiles, such as the geometric profile, will overestimate the rate of decay and this may result in a situation where an older asset appears to be more efficient than a new asset of the same rating. These assets will appear to be similar under a one hoss shay assumption.³⁶³

We agree with Economic Insights' recommendation that capex is not an appropriate measure of capital inputs. Capex represents new capital assets and does not measure the annual use of capital assets. Capex, however, does contribute to changes in annual capital services flow.³⁶⁴

In our issues paper, we proposed using RAB depreciation as a practical measure of capital inputs because it provides useful information on the flow of capital services.³⁶⁵ However, participants did not support this proposal. The MEU considered it inappropriate to use RAB depreciation because depreciation is the recovery over time of an investment made; it has no relationship to the outputs that are achieved.³⁶⁶ Similarly, Aurora Energy objected to using RAB depreciation, given issues such as fully depreciated assets still in service and past optimisations.³⁶⁷ SP AusNet argued RAB depreciation may be affected by changes in prices over time and by the assumed remaining life of the asset.

We consider RAB depreciation could be a useful starting point for measuring the annual capital input.³⁶⁸ Economic Insights considered RAB depreciation could produce a series similar to a one hoss shay proxy in principle, but that it also identified the issues raised in submissions and recommended further investigating using RAB depreciation.³⁶⁹

We consider the RAB straight line depreciation proxy provides a similar result to the one hoss shay physical capital measure. Further, the depreciated RAB proxy is relatively simple to calculate. However, these two methods may not produce results that are consistent with the use of physical capital measures. We agree with Economic Insight's recommendation that these two proxies warrant further investigation.

Stakeholders noted a similarity between the physical measure of system capacity and the physical proxy for capital input quantities. However, there is no issue of similarity between these two measures according to Economic Insight, and we agree. The capital input measure is a weighted average capacity that also factors in the difference in costs between networks of different voltages. By contrast, the system capacity measure is the product of line length and transformer capacity at the distribution transformer level only, so there is no adjustment for different weighted average MVA capacities.³⁷⁰ This reflects the final capacity that customers are able to draw on.

³⁶² SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 19.

³⁶³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 60.

³⁶⁴ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 50.

³⁶⁵ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 71.

³⁶⁶ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 29.

³⁶⁷ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 14.

³⁶⁸ SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper*, 15 March 2013, p. 21.

³⁶⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 63.

³⁷⁰ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 64.

Environmental variables

Environmental variables outside of a NSP's control can affect its ability to convert inputs into outputs. There is overlap between inputs, outputs and environmental variables used in previous economic benchmarking studies. Similar to outputs, there is a diversity of views in the economic literature on the choice of environmental variables.

The environmental variables discussed in this section have been identified as possible factors that may have a material effect on NSP efficiency. However, we do not currently have data on these environmental variables and our decision to incorporate these factors will depend on their materiality and statistical relationship once we have data.

The CRG noted that not all NSPs are the same. Differences include urban/rural, customer and energy density, and climate factors. The CRG argued that we need to consider which differences are material.³⁷¹ By collecting data on operating environmental factors we can account for the differences in efficiency across networks caused by operating environmental factors. The materiality of these factors can be tested as part of the data validation and testing process described below.

DNSP environmental variables

Our shortlist of environmental variables is based on the shortlist recommended by Economic Insights.³⁷² We also included an additional terrain factor that accounts for difficult terrain.

Table A.10 DNSP environmental variables shortlist

Variable	Definition	Source
Density factors		
Customer density	Customers/route km of line	RIN
Energy density	MWh/customer	RIN
Demand density	kVA non-coincident peak demand (at zone substation level)/customer	RIN
Weather factors		
Extreme heat days	Number of extreme cooling degree days (average temperature above 25°C)	BoM
Extreme cold days	Number of extreme heating degree days (average temperature below 12°C)	BoM
Extreme wind days	Number of days with peak wind gusts over 90 km/hour	BoM
Terrain factors		
Bushfire risk	Number of days with over 50 per cent of service area subject to severe or higher bushfire danger rating	BoM and FAs
Rural proportion	Percentage of route-line length classified as short rural or long rural	RIN

³⁷¹ AER, 'Meeting summary', *Consumer Reference Group (CRG) Meeting No. 3*, 24 April 2013, p. 4.,
³⁷² Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 74.

Vegetation growth and encroachment	Percentage of route-line length requiring active vegetation management by the DNSP	DNSPs
Standard vehicle access	Proportion of network that does not have standard vehicle access	DNSPs
Service area factors		
Line length	Route-length of lines	RIN

Abbreviations: BoM – Bureau of Meteorology, FAs - fire authorities

Density factors

We consider density variables are the most important environmental factors that may affect DNSPs' costs. A DNSP with lower customer density is likely to require more network assets to service the same number of customers, for example, than does a higher density DNSP. Since the lower density DNSP will require more inputs to produce the same level of outputs, it will appear to be inefficient relative to the higher density DNSP. Some adjustment for the impact is therefore required.

DNSP representatives noted demand density is more important than energy density as an environmental variable. We consider both types of density should be recognised as a potential environmental variable. There is likely to be some correlation between the density variables and it would not be practical to incorporate all the different density measures into one model.

We also note the choice of density variables must be made in conjunction with the selection of output variables to avoid double counting. If peak demand and customer numbers are modelled as outputs, for example, demand density does not need to be included as an operating environment factor.

Weather

We consider it appropriate to account for differences in extreme weather conditions as environmental variables. Extreme hot and cold days place additional strain on a DNSP's network because customers have greater demand for heating and cooling. The additional load through extra air conditioner use may place a greater load on the network during peak energy use periods. However, at this stage, we cannot decide on a method for accounting for extreme weather until more data are available to perform sensitivity analysis.

An appropriate starting point to account for extreme temperatures is to take the number of days where the average temperature is above 25°C or below 12°C, as recommended by Economic Insights.³⁷³ This range is 6.5°C above and below AEMO's base temperature of 18.5°C.³⁷⁴ The degree day measurement takes the product of the temperature in degrees above/below the threshold multiplied by the number of days.

We consider these temperature thresholds to be indicative, although they may be adjusted to thresholds where the change in energy use is statistically significant in our econometric analysis. Alternatively, they could be based on a qualitative assessment after consulting with industry and meteorological experts.

An alternative to the average degree day measure is to take the maximum temperature for the day. An extreme hot day may occur when the maximum temperature reaches 40°C and an extreme cold day may occur when the maximum temperature does not exceed 10°C. However, unlike degree days,

³⁷³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 75.

³⁷⁴ Australia Energy Market Operator, *South Australian supply and demand outlook*, 2011, p. 1.

this measure does not account for the magnitude above or below the thresholds, so a 45°C day would have the same effect on energy use as a 41°C day. To account for magnitude, we will require additional assumptions on how energy demand is affected by different levels of extreme weather.

Another issue raised in submissions and workshops is the effect of sustained extreme weather such as heat waves where the temperature may exceed 40°C for consecutive days.³⁷⁵ We will need more research to examine the relationship between the weather and providing more capacity to meet the increased demand. Specifically, more work is needed to identify the appropriate temperature thresholds for extreme weather and whether or not an average or maximum temperature measure is appropriate. We will also need more research on how much energy use will scale above the threshold temperature and the cumulative effects of sustained periods of extreme weather and the effect on network reliability. Grid Australia submitted in some cases the TNSPs will be better placed than the Bureau of Meteorology to quantify factors in a way that is relevant to their network.³⁷⁶

We consider research into the effect of weather on NSPs' networks should be conducted during our model testing and validation process. As a part of this process, stakeholders will be given the opportunity to conduct their own economic benchmarking analysis and submit this information to us.

Over time, as more analysis is conducted on the effect of weather on a DNSP's network, a 'climatic' difficulty index (that measures the overall effects of extreme weather on a network) may be developed. It may include the effect of different temperatures that exceed the thresholds (that is, the difference between a 35°C degree-day and a 40°C degree-day) and it may account for sustained extreme weather conditions.

We consider an environmental variable that accounts for extreme wind conditions is also appropriate. Economic Insights recommended the number of days with peak wind gusts above 90 km/h. This wind speed is associated with extreme weather conditions such as cyclones and tornados, which may have a significant impact on reliability and costs for DNSPs.³⁷⁷

Terrain

We consider terrain factors (such as bushfire risk, rural proportion, difficult terrain, vegetation growth and vegetation encroachment) are appropriate environmental variables to include in our short list. There is currently a dearth of terrain summary indicators, but Economic Insights recommended three:³⁷⁸

- The bushfire risk indicator accounts for DNSPs that must undertake more stringent vegetation management, inspecting and maintenance programs in areas with higher bushfire risk.
- The rural long and rural short proportion of a network will account for differences in densities. This measure provides an alternative that accounts for similar environmental factors to the density measures.
- The proportion of a DNSP's route-line length requiring active vegetation management accounts for DNSPs operating in forested or heavily treed areas (and therefore undertake more vegetation-related expenditure).

³⁷⁵ AER, 'Meeting summary - DNSP outputs and environmental factors', *Workshop 12: Economic benchmarking techniques work-stream - Measurement of outputs and environmental factors (Distribution)*, 30 April 2013, p. 5; CitiPower, Powercor Australia and SA Power Networks, *Submission to AER on economic benchmarking of electricity distribution service providers*, 30 May 2013, p. 8.

³⁷⁶ Grid Australia, *Electricity benchmarking data requirements - Grid Australia comments*, July 2013, p. 7.

³⁷⁷ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 75.

³⁷⁸ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, pp. 76–77.

We consider 'difficult to access terrain' is another environmental variable that may materially affect a DNSP's costs. There is no simple measure of difficult terrain, but we define it as terrain that requires special vehicles (such as helicopters or special all-terrain vehicles) that are not the standard vehicles typically used for maintenance works.

TNSP environmental variables

Our shortlist of environmental variables is based on the shortlist recommended by Economic Insights.³⁷⁹ We have also included one additional terrain factor that accounts for difficult terrain.

Table A.11 TNSP environmental variables shortlist

Variable	Definition	Source
Weather factors		
Extreme heat days	Number of extreme heat days (average temperature above 25°C)	BoM
Extreme cold days	Number of extreme cold days (average temperature below 12°C)	BoM
Extreme wind days	Number of days with peak wind gusts over 90 km/hour	BoM
Average wind speed	Average recorded wind speeds for a representative sample of weather stations	BoM
Terrain factors		
Bushfire risk	Number of days with over 50 per cent of service area subject to severe or higher bushfire danger rating	BoM and FAs
Rural proportion	Percentage of route-line length classified as short rural or long rural	RIN
Vegetation growth and encroachment	Percentage of route-line length requiring active vegetation management by the TNSP	TNSPs
Standard vehicle access	Proportion of network that does not have standard vehicle access	TNSPs
Altitude	Percentage of circuit line length above 600 metres	TNSPs
Network characteristics		
Line length	Route length of lines	IDR
Variability of dispatch	Proportion of energy dispatch from non-thermal generators	TNSPs
Concentrated load distance	Greatest distance from node having at least 30 per cent of generation capacity to node.	TNSPs

Abbreviations: RIN – Regulatory information notice, BoM – Bureau of Meteorology, IDR - information disclosure requirements, FAs - fire authorities

Grid Australia identified the following environmental variables that could potentially affect a TNSP's costs that are outside of the TNSP's control:

³⁷⁹ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 79.

- location and type of generation network
- variability of generation dispatch patterns due to intermittent generation, for example where contributions from hydro or wind generation are material
- location and distribution of loads, whether centralised or distributed among major flow paths, across each network
- length/distance and topology (that is, the degree of meshing or extension of each transmission network, potentially reflected as 'network density')
- system operating voltage and power carrying capability of lines
- major circuit structures (for example, single circuit or double circuit, which can affect credible contingencies in the NEM)
- weather (that is, natural performance characteristics of the network related to storms, bushfires and other weather related events, which in turn can depend on factors such as altitude, wind and the propensity for natural phenomena like cyclones)
- terrain
- peak demand
- different jurisdictional standards, such as planning standards
- age and rating of existing network assets
- timing of a TNSP in its investment cycle, given the lumpy nature of investments
- extent of implications of NER 'technical envelope' requirements, such as those in the schedules in Chapter 5 (for example, voltage stability, transient stability, voltage unbalance, and fault levels)
- variations in cost drivers between jurisdictions.

Some of these environmental variables were considered as a part of our inputs and outputs specifications, such as peak demand, system operating voltage and power carrying capability of lines. Further, although all these variables may affect a TNSP's costs, the nature of economic benchmarking means only the most material environmental variables can be included.

Workshop participants noted the difficulties in quantifying some of the environmental factors, and considered such limitations should not be ignored.³⁸⁰ We consider environmental variables will be a significant part of our data validation and model testing process. We also consider it important to collect the relevant environmental variable data. Further, as noted in our workshops, environmental variables could also be accounted for qualitatively, and the findings of economic benchmarking will be considered in conjunction with other analyses.³⁸¹

³⁸⁰ AER, 'Meeting summary - TNSP outputs & operating environment factors ', *Workshop 6: Economic benchmarking techniques work-stream - Network outputs (Transmission)*, 14 March 2013, p. 4.

³⁸¹ AER, 'Meeting summary - DNSP outputs and environmental factors', *Workshop 12: Economic benchmarking techniques work-stream - Measurement of outputs and environmental factors (Distribution)*, 30 April 2013, p. 6.

Weather factors

We consider the weather variables for DNSPs are also appropriate for TNSPs. In addition to the extreme heat, extreme cold and extreme wind days variables, we support Economic Insights' recommendation to include average wind speed.³⁸² High average wind speed will cause lines to sway more and therefore suffer increased rates of wear and tear. It may also increase opex costs.

Terrain

We consider the terrain factors for DNSPs are also appropriate for TNSPs. In addition to these factors, we support Economic Insights' recommendation to include an altitude variable because altitude may affect capex design and opex costs.³⁸³ We recognise there may be some overlap between altitude and standard vehicle access, so our models may only include one of these variables, with the other included as a part of sensitivity analysis.

Network characteristics

We consider the following network characteristics, as recommended by Economic Insights, are appropriate environmental variables for TNSPs:³⁸⁴

- line length—The length of transmission lines is generally beyond TNSP control and may depend on whether the line services major cities or regional areas.
- variability of dispatch and concentrated load distance—TNSPs that are closer to generation centres and concentrated large load centres have an advantage over TNSPs with more diffuse generation centres and more diffuse and smaller load centres. A similar measure is the proportion of non-thermal dispatch, such as hydro and wind turbines, which are generally more diffuse than thermal sources.
- degree of meshing—Economic Insights recommended a measure of transmission network density that reflects the degree of meshing versus extension of the network. A more meshed network will be able to provide higher levels of reliability than a less meshed network. A possible indicator is MVA system capacity per route kilometre of line.

We consider these network characteristics to be appropriate for sensitivity analysis, although we recognise the limitations in including all network characteristic variables. There may also be issues with double counting and multicollinearity, which will limit the number of network characteristics to only the most material variables.

Back cast data

We consider in general our back cast data requirements are aggregated at a high level and based on data that should already exist in the NSPs' systems. We note that there will be varying degrees of quality in the back cast data, but overall the quality of back cast data available to us will be sufficient to conduct economic benchmarking analysis.

Back cast data are historical data to be provided to us for economic benchmarking. We may have already received some back cast data as a part of the NSPs' statutory reporting requirements. However, we will require new data or more detailed versions of existing data to implement economic benchmarking.

³⁸² Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 80.

³⁸³ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 81.

³⁸⁴ Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 81.

Our back cast data template will require all NSPs to report in a consistent format, unlike the current statutory reporting requirements where the RINs vary across jurisdictions. We acknowledge some of the back cast data required may not be consistent with the NSP's internal reporting systems. Further, data may have various levels of internal and external auditing and these may not be consistent across all NSPs.

Ideally we prefer 10 years of back cast data for robust economic benchmarking. The process for obtaining back cast data will be independent of the annual RIN/RIO process. Generally, we expect NSPs already collect much of the back cast data for internal purposes. Therefore, we do not consider reporting back cast data for economic benchmarking is likely to be onerous for the NSPs.

Some participants were concerned about using back cast data for economic benchmarking. Jemena submitted the data currently available are not comprehensive or reliable enough to support the use of economic benchmarking as a deterministic tool.³⁸⁵ Similarly, CitiPower and Powercor argued that the quality of historical data will diminish and a greater degree of judgment and estimation would need to be applied, and that 10 years is a longer period than required for tax and financial reporting purposes. They also argued it is essential that the interpretations and assumptions are transparent.³⁸⁶

Other submissions noted that 10 years of back cast data may not be available for some data items and that information reporting requirements have changed over the last 10 years. These issues may result in some consistency problems about definitions and data collection.³⁸⁷

The NSW DNSPs consider there are five years of back cast data available which can be supplemented by forecasts for the next regulatory period to give an indication of trends in expenditure.³⁸⁸

Our position on data quality is discussed in the implementation issues chapter. At this stage, it is not possible to determine how likely we are to rely on economic benchmarking relative to our other assessment techniques. We recognise more assumptions (about factors such as cost allocations) will be required for older data than for more recent data. NSPs will be required to state their assumptions and make them publicly available.

Our data validation and model testing process (discussed below) is intended to provide a data set that will be comprehensive enough to perform economic benchmarking. We consider 10 years of reasonable quality data will provide a good representation of an NSP's historical performance and will reduce the impact of volatility.

Data validation and model testing

We consider there is merit in having a data validation and model testing process before applying economic benchmarking results. Modelling constraints mean most economic benchmarking techniques cannot incorporate every variable that may affect an NSP's expenditure. Further, it may not be possible to collect the data required to apply every model specification.

³⁸⁵ Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 3.

³⁸⁶ CitiPower and Powercor, *Submission to AER on draft data list for economic benchmarking*, 25 June 2013, p. 1.

³⁸⁷ These include submissions from the New South Wales DNSPs, SP AusNet, CitiPower, Powercor, SA Power Networks and Jemena.

³⁸⁸ Ausgrid, Endeavour Energy and Essential Energy, *NSW DNSP submission on Forecast Expenditure Assessment Guideline -Issues Paper*, 14 March 2013, p. 5.

Workshop participants recommended an independent review of our application of economic benchmarking and the data required. Workshop participants also requested the data be made available to all stakeholders before the results are published.

The PC recommended the AER should make all benchmarking input data publicly available (recognising the businesses being benchmarked are regulated monopolies) except where the data can be demonstrated to be genuinely commercial-in-confidence. Stakeholders should also play a role in commenting on results and be encouraged to undertake their own analysis, and have the information required that would allow them to replicate any models. The AER should also submit its economic benchmarking analysis for independent expert peer review.³⁸⁹

The Australian Government supported the need for transparency and the benefits of the AER being able to publish information. The Government considered the requirements in the NEL and the NER, which describe how data are managed, generally strike the right balance between transparency and confidentiality. Further, the Government did not consider that it is appropriate to specify the review mechanisms for decisions of an independent regulator.³⁹⁰

We consider stakeholders should be informed of preliminary economic benchmarking results before they are adopted in our regulatory determinations. Similarly, the first annual benchmarking report and that data should be made publicly available to allow for stakeholders to perform their own analysis. The consultation process for data validation and model testing is discussed below.

We consider a robust testing process that involves all stakeholders is desirable, especially for 2014 when the first annual benchmarking report is published. However, it may not be feasible to conduct the same specification testing process in subsequent years, unless there are material changes in the model specifications or data used for economic benchmarking, which in turn may cause substantial changes in the analysis and results. Stakeholders are also free to engage experts on economic benchmarking to prepare their feedback during our data validation and model testing process.

The PC also recommended international collaboration, which would facilitate meta-studies, which help identify common variables that lead to robust benchmarking results.³⁹¹ We consider international collaboration of economic benchmarking to be an appropriate long term goal and our economic benchmarking should not be limited to a comparison of Australian NSPs. However, at this stage we are focusing primarily on gathering a robust data set for Australian NSPs with reference to results and methodologies from regulators in other jurisdictions.

The sections below discuss our intended processes to validate the data and test the model. In principle, the data validation and model testing processes should be transparent, consultative and well documented. We will use internal and external expertise when appropriate.

Data validation

We will commence our data validation process once we have received completed back cast data templates. This process will involve three steps:

³⁸⁹ Productivity Commission, *Electricity network regulatory frameworks*, Inquiry report no. 62, vol. 1, 9 April 2013, pp. 329-333.

³⁹⁰ Australian Government, *Electricity Network Regulatory Frameworks: Australian Government response to the Productivity Commission inquiry report*, June 2013, pp. 6-7.

³⁹¹ Productivity Commission, *Electricity network regulatory frameworks*, Inquiry report no. 62, vol. 1, 9 April 2013, p. 331.

1. We will conduct a preliminary check of data to identify anomalies and correct errors, and a confidentiality check to prepare the data for public release. This will involve bilateral consultation with the relevant NSPs if any issues arise. This is likely to be iterative.
2. We will publish refined data to allow interested parties to cross check data and conduct their own analysis.
3. Interested parties will provide feedback on overall data quality and any specific data issues that arise.

This process will help us establish a database with quality economic benchmarking data on NSPs and ensure interested parties can provide feedback before the economic benchmarking model is developed. The finalised database, which accounts for the feedback, will also be publicly released (subject to the confidential information constraints).

The database will be maintained and further developed when new data are collected in subsequent years.

Model development

We consider developing our economic benchmarking models should also be a consultative process. We are currently consulting with stakeholders via workshops on input-output specifications and their measurement. This informs our decisions on preferred and alternative model specifications.

The model development process will comprise the following steps:

- We will apply our preferred model specification to determine the productivity and efficiency performance of each NSP, using appropriate benchmarking method(s).
- We will perform sensitivity analysis on model specifications, benchmarking methods, and changes in key assumptions to test the robustness of the results. More information about the sensitivity analysis is presented in the next section.
- We will review the performance of benchmarking analysis in terms of estimation stability, sensitivity of the results, and the validity of conclusions drawn.
- We will provide our benchmarking analysis and preliminary results to NSPs for comment before they are published. Stakeholders are also invited to submit their own analysis while we develop our models.
- We will refine the benchmarking analysis based upon stakeholder comments.
- We will publish economic benchmarking results as a part of the first annual benchmarking report. Data underpinning economic benchmarking results may also be published at the framework and approach stage. Preliminary economic benchmarking results may also be published at the issues paper stage of the Directlink, Transend, and NSW/ACT reviews.

The process aims to ensure stakeholders interested in conducting their own analysis can replicate the benchmarking results reported in the annual benchmarking report and used in regulatory determinations. Stakeholders will also be able to provide feedback on the economic benchmarking results at the issues paper and draft decision stages.

Sensitivity analysis

We consider sensitivity analysis is a critical process in developing and finalising our model specifications. Our broad range of data requirements is to allow for a rigorous sensitivity analysis.

Sensitivity analysis is a method for testing a model to identify where there may be sources of uncertainty. It is an important step in testing the robustness of our economic benchmarking analysis. It helps to identify appropriate economic benchmarking variables, to test the overall robustness of our economic benchmarking techniques and to further understand the relationships between our inputs, outputs and environmental variables.

It is adopted here to test the materiality of differences between alternative model specifications and/or benchmarking techniques. If a variable of interest has not been included in the preferred model specification, for example, it may be added in as a part of the testing phase. If this results in material difference from the results of the preferred model, further considerations to explain the sources of the differences are required. Further actions may include revising the model specifications or addressing the limitations in the usefulness of benchmarking results.

Jemena was concerned that experts could not agree on the appropriate inputs and outputs and that the TFP growth estimates were sensitive to different model specifications.³⁹² It also considered a full range of drivers should be explored and sensitivities to the drivers should be tested through trial runs of the AER's models before deciding on which drivers are the most appropriate.³⁹³

We consider experts are likely to adopt different techniques to assess expenditure, partly reflecting the question the analysis is attempting to answer. Engineering reviews from experts may reach different conclusions on the appropriate cost and methodology for a capex project, for example. The lack of overall consensus on the appropriate input-output specifications among experts may reflect their respective historical positions and current practices, and thus indicates the importance of sensitivity analysis when assessing expenditure.

Although the input and output specifications may not be identical, other benchmarking studies used similar variables and the differences are mainly attributed to practicality issues such as data availability. Our model specifications relate specifically to NSPs in the NEM and this is why we have consulted extensively with industry stakeholders.

We will also be using a long time series of data provided to us by the NSPs. This will provide less constraints compared to studies conducted by other researchers that utilised only publicly available information.

If the different benchmarking techniques and model specifications, each with their own strengths and weaknesses, broadly produce similar results this may indicate the robustness of our benchmarking analysis and the validity of the inferences drawn from the results. Without performing such a sensitivity analysis, the robustness of our benchmarking analysis will remain in doubt. Our workshops also noted the imprecision in all assessment methodologies and why it is important to understand the error.³⁹⁴

³⁹² Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 7.

³⁹³ Jemena Limited, *Response to AER benchmarking questions*, 28 June 2013, p. 2.

³⁹⁴ AER, 'Meeting summary – economic benchmarking applications', *Workshop 17: Economic benchmarking techniques work-stream - Prescription in the EFA guideline, potential application techniques (Transmission & Distribution)*, 6 June 2013, p. 4.

We consider selecting inputs, outputs and other aspects of model specifications should be properly informed by sound economic theory, in-depth engineering knowledge and rigorous cost driver analysis. Public consultation with the stakeholders provides one way to improve our knowledge in the area. If model specifications cannot be settled this way, it is useful to apply multiple model specifications to test consistency. In some cases, the inability to produce consistent results requires further investigation so benchmarking results can be supported by more rigorous and refined analysis.

Importantly, not all variables that capture the essential aspects of NSP operation can be included in each model specification, given data availability and modelling constraints. Most benchmarking techniques inevitably require some degree of aggregation of inputs, outputs, and environmental factors into a few variables. Generally, as more variables are included in a regression, the degrees of freedom decrease and the results from a small sample are likely to be less informative. Similarly, as the number of inputs and output increases in DEA, the number of dimensions for comparing the NSPs accelerates, and the NSPs are more likely to be found efficient. Sensitivity analysis can help to identify the most relevant variables without exceeding the degrees of freedom restrictions inherent in the estimation techniques.³⁹⁵ We will test multiple model specifications for each economic benchmarking technique.

³⁹⁵ For example, the general rule of thumb for DEA is the sample size should be no less than the product of the number of inputs and number of outputs, or three times the sum of the number of inputs and outputs, whichever is larger.

B Category analysis

This attachment outlines our proposed approach to assessing the different categories of opex and capex, the reasoning for our proposed approach, and the data that we will require for our assessment.

As discussed in chapter 4, our proposed approach to assessing expenditure is broadly consistent with our approach in previous determinations. However, for opex we intend to assess the efficiency of base expenditure in more detail than previously and we intend to develop a single measure of productivity forecast to use to adjust forecast expenditure. For capex we intend to assess expenditure categories in more detail than previously. We will generally look for greater economic analysis to justify the expenditure. The analysis of standardised data outlined in this section will be used to assess NSP forecasts of expenditures as well as feature in our new annual benchmarking reports.

The remainder of this attachment covers the detailed proposed approach to assessing:

- augmentation capex
- demand forecasts
- replacement capex
- customer initiated capex
- non-network capex
- maintenance and emergency response opex
- vegetation management opex
- overheads.

B.1 Augmentation expenditure forecast assessment

This section discusses the contents of clause 4.2 of the Guidelines, which sets out our approach to assessing the augex component of a NSP's capex forecast. Augex is typically capex required to address constraints arising on the electricity network as demand increases.³⁹⁶ Demand forecasts are therefore a critical input to NSPs' development of augex forecasts.³⁹⁷ Section B.2 discusses our demand forecast assessment approach.

Increasing demand is generally an uncontrollable variable for NSPs. It increases the risk of the NSP not meeting the maximum demand at the desired quality or reliability standard.³⁹⁸ One solution to these constraints is for NSPs to undertake augex projects. This typically involves augmenting network components to ensure they have sufficient capacity to meet the forecast demand. Examples of augex projects include:

³⁹⁶ Chapter 10 of the National Electricity Rules (NER) defines a 'constraint' as a limitation on the capability of a network, or part of the network, such that it is unacceptable to transfer the level of electrical power that would occur if the limitation was removed. Increasing demand may signify the level of electricity transferring through a particular area of a distribution network is approaching or exceeding the capacity of the zone substation that services the area, for example. We acknowledge non-demand driven augex may be efficient where, for example, legal obligations require them or market benefits exist.

³⁹⁷ As we discuss in section B.2, NSPs must specify the demand forecast they used to assess potential constraints (and solutions) in the network. Such considerations include whether the demand forecast they used is spatial or system level, raw or weather corrected, or 50 per cent probability of exceedance (PoE) or 10 per cent PoE.

³⁹⁸ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 102.

- increasing the capacity of substations
- establishing new substations
- upgrading existing lines
- establishing new lines.

An alternative to augmenting the network is for NSPs or other parties to implement non-network solutions to constraints, including demand management initiatives.

The efficient solution for such constraints—network augmentation or non-network solutions—will depend on various factors including network configuration, asset utilisation, demand growth and the feasibility of other options. This makes the expenditure profile for augmentation projects non-recurrent and less predictable than other expenditure types. Hence, trend analysis is not ideal as a principal technique for augex assessment.³⁹⁹

Augex is a material expenditure category and can represent well over 50 per cent of capex in some years. The scale and proportion of augex work can vary dramatically across NSPs and over time.

B.1.1 Proposed approach

Our augex forecast assessment approach will remain broadly similar to our past approach.⁴⁰⁰ We will:

- assess a NSP's forecasting approach
- consider our assessment of the NSP's capital governance framework from the previous determination
- perform detailed reviews of a sample of projects with assistance from technical and other consultants. We will pay particular attention to the extent the NSP considered non-network solutions as alternatives to augmentation projects
- infer the findings of those reviews to the rest of the augex population, or a subset of that population depending on the characteristics of the projects.

We are currently developing a technique that produces a forecast of a NSP's future augex (the augex model). The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.⁴⁰¹ The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the NSP over a given period.⁴⁰² In this way, the augex model accounts for the main internal drivers of augex that may differ between NSPs, namely peak demand growth and its impact on asset utilisation. We discuss the augex model in more detail below.

In addition, we will collect data on the major assets that comprise augmentation projects (asset data), such as transformers for substations or overhead lines for feeders. We will collect unit costs and volumes for major assets, as well as some physical data such as asset voltage. Asset data are not inputs to the augex model (we describe the information requirements of the augex model and asset

³⁹⁹ Section B.1.2 discusses the non-mechanistic nature of augmentation projects in more detail.

⁴⁰⁰ For more information on the AER's augex assessment approach in past determinations, see the AER's website (www.aer.gov.au).

⁴⁰¹ Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

⁴⁰² For more information, see: AER, *Guidance document: AER augmentation model – data requirements*, June 2011.

data analysis below). Rather, we will use asset data for analysis that complements the augex model. We discuss asset data analysis in more detail below.

We will use the augex model and asset data to inform and support our augex forecast assessment. The augex model and asset data will enable greater comparison between NSPs and assist us in targeting projects and/or programs for detailed review. We will also likely use the augex model and asset data in detailed reviews. We may use benchmark unit costs of major assets to 'build up' an augmentation project and compare this with the NSP's project costing, for example. The augex model and asset data may also assist in adjusting augex forecasts if we find evidence of inefficiency.

While changes in demand are usually the principal drivers for augmentation projects, some augmentation projects may not be directly related to demand growth. NSPs reiterated this during our workshops.⁴⁰³ TNSPs may undertake an augmentation project because it produces net market benefits, for example.⁴⁰⁴ We will request NSPs to indicate whether the augex information it provides is demand related or non-demand related. We will assess the two types of augex separately if appropriate.

Augex model

We will use the augex model to assess augex forecasts, including.⁴⁰⁵

- as a point of comparison with a NSP's augex forecast
- for benchmarking
- as a filter to identify areas of the augex forecast that require detailed engineering review
- for informing any adjustments we make to a NSP's augex forecast.⁴⁰⁶

Ideally, the augex model would assist in identifying outliers in a NSP's augex forecast.⁴⁰⁷ We do not intend to use the augex model as the sole reference point to deterministically set the augex component of a NSP's capex forecast. The augex model is one of several techniques we will use to assess augex forecasts. However, this does not preclude us from substituting some or all of the forecasts from the augex model for some or all of the augex components of a NSP's capex forecast. We would do so if we consider it appropriate, after considering all available evidence at the time of a determination.

Asset data analysis

We will collect data on the major assets that comprise augmentation projects. This will include unit costs, volumes and physical data (such as voltage). Such asset data are not intended as inputs to the augex model. Rather, we will use it for analysis that is separate, but supplementary to the augex model. We will use asset data to develop benchmarks such as unit cost benchmarks for the major

⁴⁰³ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 3.

⁴⁰⁴ Grid Australia, *Expenditure forecast assessment guidelines issues paper*, 18 March 2013, p. 33.

⁴⁰⁵ For more information, see AER, *Guidance document: AER augmentation model – data requirements*, June 2011.

⁴⁰⁶ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 4; AER, 'Augex tool tutorial', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

⁴⁰⁷ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 1.

assets that comprise augmentation projects. We may also be able to use such benchmarks for adjusting augex forecasts, if required.

The following include some benchmarks we will use in future determinations and annual benchmarking reports (though it is not an exhaustive list):

- Benchmarks for major assets
 - \$/megavolt amperes (MVA) added for transformers at substations
 - \$/switchgear at substations for voltage classes
 - \$/pole/tower (including structures) for lines and feeders for voltage classes
 - \$/km of overhead cables for lines and feeders for voltage classes
- Benchmarks for labour or materials
 - \$/unit of labour for civil works at substations or lines
 - \$/unit of materials for civil works at substations or lines
 - \$/unit of labour for design, surveying and other costs at substations or lines

Summary of expected data requirements

NSPs must support their augex forecasts with comprehensive and rigorous evidence. We will pay particular attention to the extent NSPs seriously considered non-network solutions in developing their augex forecasts. NSPs must discuss their general approach to considering non-network solutions (as alternatives to augex) in their proposals. For example, NSPs may indicate the documents in their capital governance framework that details this consideration, for example. As part of their proposals, NSPs must also provide documentation that details their consideration of non-network solutions as it relates to material augex projects and/or programs.⁴⁰⁸ Such documentation should describe:

- the terms and conditions the NSP specified to non-network solution providers
- net present value (NPV) analysis
- other factors the NSP considered in deciding on the augex project, rather than the non-network solution, as the efficient solution to the constraint.

Documents that detail the NSPs' consideration of non-network solutions include (but are not limited to) those the NSP developed as part of regulatory investment tests for transmission and distribution.

In addition, we will require NSPs to provide data for the purposes of the augex model and asset data analysis, which we discuss below.

⁴⁰⁸ 'Material' in this case will be defined in the relevant RIN.

Augex model

The augex model handbook contains details on the augex model, including information requirements and the algorithms and assumptions that underpin it.⁴⁰⁹ This section summarises the information we will collect to populate the augex model.

The augex model requires information for network 'segments', where segments represent typical planning components (usually lines and substations of various types).⁴¹⁰ We will collect information for each segment of a NSP's network, including:

- voltage, and primary type of area supplied by the segment
- maximum demand at each network segment (historical and forecast)
- measures of capacity at each network segment
- measures of capacity added at each network segment
- measures of the cost of capacity added at each network segment
- utilisation thresholds of assets in the network segment, where utilisation above these thresholds triggers the need for augmentation
- capacity factors
- unit costs (\$/MVA).⁴¹¹

Asset data analysis

We will collect cost and other information on the major assets that comprise augmentation projects. We will also collect cost information on the civil works and survey and design components of those projects.

We will collect this information for projects grouped by network segment, consistent with the grouping in the augex model. Broadly speaking, NSPs can divide their network into 'lines' segments and 'substations' segments for the purposes of the augex model. For each augex project, we will require NSPs to estimate unit cost and volume data based on the nature of the augmentation (project type), and the major assets that comprise the projects. For example, substation augex will include the following project types:

- new substation establishment
- substation rebuild
- substation upgrade
- other (NSP to describe)

These project types will comprise the following major assets and works:

⁴⁰⁹ We are developing the augex model, including the handbook, in a separate work stream.

⁴¹⁰ AER, 'Slides - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Distribution)*, 8 March 2013.

⁴¹¹ We are investigating incorporating a factor into unit costs that captures network size and/or density. The AER may use a unit cost measure such as \$/MVA/km, for example.

- transformers
- switchgear
- capacitors
- reactors
- civil works (labour)
- civil works (materials)
- design, surveying and other costs (labour).

If NSPs do not have disaggregated cost data, they should estimate these costs from the total costs of the project and describe the basis of their estimation.

B.1.2 Reasons for the proposed approach

As discussed in section B.1.1, our proposed approach to assessing augex forecasts is broadly similar to our approach in past determinations. In particular, detailed project reviews will continue to be an important component of our assessment approach. This is because augex projects are highly variable and unique, so trend analysis by itself does not provide an adequately rigorous assessment of augex (see discussion below).

However, we will collect more detailed augex information for the augex model and asset data analysis, as we discussed above. The augex model and asset data analysis will provide a more complete picture of the augex forecast upfront and will add rigor and transparency to the augex forecast assessment process.

The augex model and asset data analysis complement each other. The augex model can identify the network segments that appear inefficient and hence require greater scrutiny, for example. This removes some of the reliance on judgement and our consultants' industry experience when selecting samples for detailed review. Experience may allow us to reduce or avoid the need to investigate some network segments if the model outcomes are consistent with efficient benchmarks for similar work.

The augex model also provides a point of comparison for a NSP's augex forecast. In past determinations, we had no points of comparison for augex forecasts except past expenditure (which is of more limited use for augex forecast assessments). The augex model enables inter-NSP and intra-NSP comparison at the aggregate level, and at various levels of disaggregation (for example, at the segment group level). We will also be able to perform inter-NSP benchmarking, for example, of unit costs (\$/megawatt), and capacity added per megawatt of peak demand increase. We may also be able to use the augex model to assist in adjusting a NSP's augex forecast if necessary.

Similarly, we can use asset data to compare a NSP's unit costs for major components of augmentation projects (such as transformers or lines). Such information will be useful in a detailed project review as a check on the cost components that make up a NSP's augex project. This will add rigor, objectivity and transparency to detailed reviews compared with past determinations, where technical consultants' database of augmentation costs may have been disparate and incomplete. In these cases, our technical consultants would have needed to rely more on judgement and industry experience. While useful, basing assessments primarily on judgement and industry experience lacks transparency and rigor.

Our approach, and associated information requirements, will also facilitate greater understanding of the drivers of augex and facilitate retention of such knowledge. In past determinations, we collected augex information at a high level. This provided little opportunity to understand the drivers of augex beyond basic trend and ratio analysis. We therefore typically had to request more detailed information, such as business cases, from NSPs. Such information facilitated our understanding of the drivers of augex projects, but generally we could not use the information for comparison or benchmarking purposes because it was often highly specific to a project. This also limited the degree to which the findings of particular projects could be used to form inferences across broader project types. We also could not use such information beyond a particular determination. Collecting augex at a high level also meant our approach to assessing augex forecasts was ad hoc and unsystematic across NSPs.

By collecting consistent information for the augex model and asset data analysis, respectively, we will have a more systematic, transparent and consistent assessment approach. We will also be able to use such consistent data beyond the confines of a particular determination, for example, in our annual benchmarking reports.

Application of our approach to DNSPs and TNSPs

We will apply our proposed approach to assessing augex forecasts of both DNSPs and TNSPs. In doing so, we acknowledge the operating environments and cost drivers that affect DNSPs and TNSPs are different. We will reflect those differences in our approach to assessing augex forecasts.⁴¹² Grid Australia stated that augex for TNSPs depends to a greater extent on the circumstances of individual assets than is the case for DNSPs, for example. Hence, TNSPs rely on statistical projections of expenditure less than DNSPs. This is partly because TNSPs have fewer assets with higher consequences of failure than DNSPs.⁴¹³

However, these differences do not detract from applying the same techniques to assess the augex forecasts of TNSPs and DNSPs. Detailed reviews are important in assessing augex generally because they are variable and unique for DNSPs and TNSPs. Similarly, the augex model and asset data analysis are useful in targeting projects and/or programs for detailed review in distribution and transmission determinations. They will also inform the detailed review and any inferences from those reviews.

Although we will apply the same techniques, differences between DNSPs and TNSPs mean we may emphasise different aspects of our approach in particular situations. We may rely more on asset data analysis when assessing a TNSP's augex forecast, for example. TNSPs have fewer but higher cost assets, so we can focus our attention more on the build up of individual projects during a transmission determination. In this case, we would use the augex model more to assist in selecting projects for detailed review. We will also use it as a point of comparison for the TNSP's augex forecast, although we may place less weight on the augex model as the basis for adjustments. Conversely, and as Grid Australia noted, DNSP augmentation programs are more conducive to modelling or statistical projections, given they tend to be lower in cost but higher in volume compared to TNSP investments. Hence, we may place more emphasis on the augex model in a distribution determination, including for adjustments. Asset data analysis will support the augex model's analysis.

⁴¹² Chapters 6 and 6A of the NER also include slightly different capital expenditure factors, which reflect some of the differences between DNSPs and TNSPs.

⁴¹³ Grid Australia, *Better regulation program - Replacement and augmentation expenditure categories*, 26 April 2013, p. 1.

Similarly, the nature of proposals will differ, for example, between DNSPs, or even for the same DNSP across different regulatory control periods. We will likely need to adjust our approach to account for such differences. We will therefore discuss the details of our approach to assessing augex forecasts with individual NSPs before a determination, particularly at the F&A stage.

Highly variable and unique nature of augmentation projects

Unlike replacement projects, augmentation projects do not have a like-for-like characteristic. Demand growth increases asset utilisation, which may introduce network issues such as voltage management or triggered augmentation. NSPs may respond to such issues in various ways through either network or non-network solutions. Where network solutions are shown to be more appropriate and effective, the NSP must consider various factors to arrive at an efficient solution, including:

- forecast rate of growth of demand
- location of load or generation
- network configuration, including existing technology and capabilities
- optimal timing of solutions, because although demand forecasts are the main determinant, augex projects may also require the completion of other network project(s) to be optimal
- land use restrictions
- easement size and availability
- community engagement or opposition.

Augmentation projects tend to be lumpy in nature given long asset lives and high up front fixed costs, resulting in building excess capacity to address demand growth.⁴¹⁴ Thus, past augex trends may not be a reliable indicator of future augex requirements, and techniques such as 'base-step-trend' are not typically appropriate for augex forecasts.

This issue also brings an extra layer of complication to augex forecast assessment. In addition to assessing the costs, we must be satisfied the NSP considered all viable options to arrive at the most efficient augmentation project. In previous determinations, we assessed such options analysis in the detailed project reviews, including NPV analysis as part of the RIT-T process. However, we regularly found issues, such as:

- consideration of a limited number and/or types of options
- cultural barriers to consideration of non-network solutions
- application of unreasonable assumptions
- misstatement of planning requirements.

As outlined in chapter 4, we will expect NSPs to more clearly justify their proposed investments than they did with previous regulatory proposals. In particular, we will need to see evidence that NSPs have comprehensively considered all viable options, including non-network options, in their analysis and in forming a view on the preferred approach to addressing the relevant need.

⁴¹⁴ AER, *Draft distribution determination: Aurora Energy Pty Ltd 2012–13 to 2016–17*, November 2011, p. 113.

Augex model

General issues

Stakeholders noted some limitations of the augex model in workshops and submissions.⁴¹⁵ In many cases, this relates to the highly variable and unique nature of augmentation projects. CitiPower, Powercor and SA Power Networks, for example, were concerned about using the augex model for inter-DNSP and intra-DNSP benchmarking. They stated any benchmarking exercise must account for factors such as different jurisdictional planning requirements and the different voltages across networks. They also stated the augex model oversimplified the complex and dynamic parameters that influence augmentation decisions.⁴¹⁶

While any model will have limitations, we accept they may be more pronounced when modelling augex compared with other types of capex, given the variable nature of augmentation projects. Nevertheless, we consider the basic premise of the augex model is sound and it will provide a useful point of comparison for the augex component of a NSP's capex forecast. Further, we note the augex model is not a planning tool that addresses specific network constraints and possible solutions. Rather, it is a regulatory tool that accounts for the main driver of augmentation (changes in demand and asset utilisation). It also serves as a screening tool that provides an alternative view of augex forecasts. It will enable intra- and inter-company comparisons of historical and forecast augex, and the data we obtain will assist us in developing benchmarks.⁴¹⁷ We will also collect data that is consistent across DNSPs and TNSPs, respectively, to populate the augex model. Having consistent data is in itself important to facilitate meaningful comparisons (section B.1.2).⁴¹⁸

User groups stated the augex model may assist users to understand the scale of the networks. The augex model would also assist in identifying the areas where a NSP has higher costs, as well as areas of lower costs, relative to its peers.⁴¹⁹ Asset utilisation data would also be useful in considering the impact of different planning requirements and demand characteristics across jurisdictions.

Transitional issues

We have not yet used the augex model in a determination so we and other stakeholders may identify issues with the model not considered in our development of the Guidelines. Despite this, we consider it important to include the augex model in our suite of techniques. User groups stated stakeholders should focus on improving the augex model and regulatory process, rather than excluding it based on perceived limitations. For example, one NSP stated we still need to resolve some issues with the augex model. When it conducted testing of the model, however, the NSP recognised the model had begun to produce reasonable results and agreed with user groups that the focus should be on deriving the maximum benefits from the model.⁴²⁰

⁴¹⁵ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 3; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 15–17; United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator*, 19 March 2013, p. 14.

⁴¹⁶ CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 15–17.

⁴¹⁷ AER, 'Slides - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Distribution)*, 8 March 2013.

⁴¹⁸ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 3.

⁴¹⁹ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 4.

⁴²⁰ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 4.

We consider applying the augex model in a determination will help resolve potential issues. It will also familiarise stakeholders with the process of using the model in a determination. Using the repex model during the Victorian and Tasmanian distribution determinations helped identify and subsequently resolve some implementation issues.⁴²¹

We are attempting to minimise complications that may arise with the augex model through the consultation process for the Guidelines.⁴²² We also trialled the augex model with several New South Wales DNSPs.⁴²³ This trial identified particular scenarios in which the augex model produced anomalous results.⁴²⁴ We subsequently addressed those issues.

There is also a question on the extent we can rely upon the augex model as a filter to target areas of the augex forecast for detailed review. If a DNSP's augex forecast for zone substations is 'close' to the model's forecast, for example, can we simply accept the DNSP's forecast as meeting the requirements of the NER? Doing so implies we would exclude that segment group from detailed review and any inference from that review. Experience will guide us in determining whether we want to investigate a segment, or whether to limit investigation to a sample of projects from representative segments. In the first tranche of determinations, we will likely review, in detail, projects from all network segments, even those the augex model suggests are at reasonably efficient levels. This will help us understand how various circumstances can affect how we use the augex model, and how we can further refine and improve this use—this is part of the learning process.⁴²⁵ More generally, experience in a determination will fine tune our application of the model and may identify further uses.

B.2 Demand forecast assessment

This section discusses clause 4.2.1 of the Guidelines, which sets out our approach to assessing the demand forecasts that a NSP uses as inputs to its expenditure forecasts. Under the NER, we must accept the capex forecast of a NSP if we are satisfied that capex forecast reasonably reflects (among other considerations) a realistic expectation of the demand forecast.⁴²⁶ We must do the same for the opex forecast of a NSP.⁴²⁷

The NER do not require us to include a decision about demand forecasts in our determinations.⁴²⁸ However, forecasts of maximum demand are a major input to decisions to invest in electricity networks.⁴²⁹ In particular, spatial demand forecasts are usually the principal driver for augmentation decisions.⁴³⁰ Augex is a significant component of NSPs' capex forecasts, comprising well over 50 per cent of capex in some years (section B.1). For this reason, demand forecast assessments are an

⁴²¹ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 3.

⁴²² AER, 'Augex demo', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

⁴²³ Endeavour Energy, Email to AER: Follow up to augex discussion, received 26 November 2012.

⁴²⁴ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 3.

⁴²⁵ Section B.1.1 discusses how we will use the augex model in more detail.

⁴²⁶ NER, clauses 6.5.7(c)(3) and 6A.6.7(c)(3).

⁴²⁷ NER, clauses 6.5.6(c)(3) and 6A.6.6(c)(3).

⁴²⁸ NER, clauses 6.12.1 and 6A.14.1.

⁴²⁹ The NER define maximum demand as the 'highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.'

⁴³⁰ NSPs typically produce two types of forecast: system level (top down) and spatial (bottom up) forecasts. A system level forecast is the demand forecast that applies to the NSP's entire network. A spatial forecast applies to elements of the network. For transmission network service providers (TNSPs), spatial forecasts would be at the level of connection points with distribution network service providers (DNSPs) and major customers. For DNSPs, spatial forecasts would be at the level of connection point, zone substations and/or HV feeders.

important consideration in our determinations. This section sets out how we incorporate our assessment of demand forecasts in our expenditure forecast assessments.

B.2.1 Proposed approach

Our demand forecast assessment approach will be broadly similar to our past approach, as we summarised in our issues paper.⁴³¹ In consultation, stakeholders broadly considered the assessment approach that we described in the issues paper was reasonable.⁴³² We will assess whether the approaches that a NSP uses to produce its demand forecast (including models, inputs and assumptions) are consistent with best practice demand forecasting. The Guidelines formalise the elements that comprise best practice demand forecasting (we describe these elements below).

Our demand forecast assessment will include reviewing the technical elements of a NSP's forecasting approaches. We will assess, for example, weather correction approaches and regression techniques for rigor and supporting evidence. We will also carry out data validation and testing of the trends that underpin the demand forecasts. This work may include checking customer number growth in different regions of the network, or cross checking data from the NSP with other data sources. We will assess whether the NSP considered a variety of sources for its inputs, and whether the input selection process potentially introduces bias to the demand forecast.

We will likely review a sample of the NSPs' spatial demand forecasts given a full review of all spatial forecasts is infeasible. In distribution determinations, for example, we will likely review in detail the demand forecasts and forecasting approaches for a sample of zone substations. Preliminary analysis, including discussions with the NSP and other stakeholders, will likely inform the appropriate approach for selecting zone substations for closer review. We may target our sample to include those zone substations associated with a relatively high capex forecast over the next regulatory control period.⁴³³ Alternatively, we may choose a random sample or a mix of targeted and random sampling.

The extent to which we extrapolate our findings on the sample to all other zone substations will depend on the issues that arise and the nature of the NSP's forecast. Our detailed review will assess whether issues appear common in the forecast, or are confined to one part of the network. We may find, for example, an unreasonable demand forecast for only one zone substation in the sample. If so, we would not extrapolate adjustments for that zone substation to other zone substations. If we find a more general issue (such as reconciliation between the top down and bottom up forecasts), then we will likely infer findings from the detailed review to the rest of the spatial forecasts.

Demand forecast assessment principles

We will assess whether a NSP's approach exhibits the following principles of best practice demand forecasting:

- accuracy and unbiasedness

⁴³¹ AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, pp. 116–118.

⁴³² Energy Networks Association (ENA), *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, Attachment B, 8 March 2013, p. 10; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 18; JEN, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013 p. 14; Major Energy Users (MEU), *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 41–42; Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 23.

⁴³³ Our aim is to ensure reasonable demand forecasts underpin the NSP's capex and opex forecasts.

- transparency and repeatability
- incorporation of key drivers
- weather normalisation
- model validation and testing
- use of the most recent input information
- spatial (bottom up) forecasts validated by independent system level (top down) forecasts
- adjustment for temporary transfers
- adjustment for discrete block loads
- incorporation of the maturity profile of a service area in spatial time series
- use of load research
- regular review.

We discuss each of these principles below.

Accuracy and unbiasedness

A NSP should ensure its demand forecasting approaches produce demand forecasts that are unbiased and meet minimum accuracy requirements. Forecasting steps include careful management of data (including removal of outliers, and data normalisation) and construction of a forecasting model (that is, choosing a model based on sound theoretical grounds that closely fits the sample data).

We will compare a NSP's previous demand forecasts with its historical demand. We acknowledge demand forecasting is not a precise science and will inevitably contain errors. However, consistent over-forecasting or under-forecasting may indicate a systemic bias in a NSP's demand forecasting approach. When such systemic bias is present in past demand forecasts, we expect the NSP to explain how it has improved its demand forecasting approach to minimise such biases. In addition, the NSP will need to support any departure from recent historical trends with evidence and a good description of the approach and assumptions leading to the departure.

Transparency and repeatability

Demand forecasting approaches should be transparent and reproducible by independent sources. The NSPs should clearly describe the functional form of any specified models, including:

- the variables used in the model
- the number of observations used in the estimation process
- the estimated coefficients from the model used to derive the forecasts
- any thresholds or cut-offs applied to the data inputs
- the assumptions used to generate the forecasts.

NSPs should keep good documentation of their demand forecasting approach, which ensures consistency and minimises subjectivity in forecasts. This documentation should include justification of

the use of judgment. It should also clearly describe the approaches used to validate and select the forecasting model.

Incorporation of key drivers

A best practice forecasting approach should incorporate all key drivers either directly or indirectly, and should rest on a sound theoretical base. NSPs should document and explain the theoretical basis and empirical evidence that underpin their selection of key drivers. They should also identify and use a suitably long time series of historical data in their demand forecasting.⁴³⁴

Weather normalisation

Correcting historical loads for abnormal weather conditions is an important aspect of demand forecasting. Long time series weather and demand data are required to establish a relationship between the two, and to conduct weather correction. The data are also necessary to establish the meaning of normal weather—that is, probability of exceedance (PoE) of 50 per cent—and relative values, which can include temperature and humidity.⁴³⁵

Weather correction is relevant to both system and spatial level forecasts. System level weather correction processes tend to be more robust and sophisticated due to data availability (such as temperature). Key driver variable data (such as dwelling stock and household income) may also not be available at a regional or zone substation level.

Model validation and testing

NSPs should validate and test the models they use to produce demand forecasts. Validation and testing includes assessing the statistical significance of explanatory variables, how well the model explains the data, the in-sample forecasting performance of the model against actual data, and out of sample forecast performance.

Use of the most recent input information

NSPs should use the most recent input information to derive their demand forecast. We may use more up to date input information as it becomes available during the determination process.

Spatial (bottom up) forecasts validated by independent system level (top down) forecasts

NSPs should prepare their spatial forecasts and system level forecasts independently of each other. Using system level data, a NSP is better able to identify and forecast the impact of macroeconomic, demographic and weather trends. On the other hand, spatial forecasts capture the underlying characteristics of individual areas in the network, including prospects for future load growth. They also have a more direct relationship with expenditure.

Generally, spatial forecasts should be constrained to system level forecasts. The reconciliation should consider the relationships between the variables that affect system level and spatial forecasts respectively. For example, NSPs should reconcile the economic growth assumptions in their spatial

⁴³⁴ The ENA noted 'definitions such as a suitable long time series can be agreed with the AER'. It is difficult to prescribe or define what constitutes a 'suitably long time series' in the Guidelines for historical demand, or other relevant data. We expect to discuss such issues with NSPs early in the determination process, preferably during the framework and approach process. ENA, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, Attachment B, 8 March 2013, p. 10.

⁴³⁵ PoE means the probability the actual weather will be such that the actual maximum demand will exceed the relevant maximum demand measure adjusted for weather correction. A 50% PoE means the maximum demand measure adjusted for weather correction is expected to be exceeded fifty out of every one hundred years.

forecasts (which are more likely to use judgement) with those in their system forecasts (for which data are more readily available).⁴³⁶

Demand forecasts at different levels of aggregation should be consistent with each other. Inconsistency at the different levels of aggregation affects the overall reasonableness of the forecasts. Accuracy at the total level may, for example, mask errors at lower levels (for example, at zone substations) that cancel each other out.

Adjusting for temporary transfers

Before determining historical trends, NSPs must correct actual maximum demands at the spatial level to system normal conditions by adjusting for the impact of temporary and permanent network transfers arising from peak load sharing and maintenance.⁴³⁷

Adjustment for discrete block loads

NSPs should incorporate large new developments in their forecasts. Discrete block loads may include aluminium smelters for TNSPs, and shopping centres and housing developments for DNSPs. They should include only block loads exceeding a certain size threshold in the forecasts. This approach avoids potential double counting, because historical demands incorporate block loads.

NSPs must also account for the probability that each development might experience delays or might not proceed.

Incorporation of maturity profile of service area in spatial time series

NSPs should recognise the phase of growth of each service area (as represented by zone substations for DNSPs, for example).

Use of load research

NSPs' demand forecasting approach should incorporate the findings of research on the characteristics of the load on their networks. For many networks, for example, it is important to establish the contributions of customers with air conditioners to normalised maximum demand. Such research can include regular surveys of customers, or appliance sales information to establish the proportion of residential customers who own air conditioning and other weather sensitive appliances over the period. The forecasting models should test the assumed relationship between customer types and network load.

Load research can incorporate many other factors that could affect the characteristics of the load on electricity networks, including:

- solar photovoltaic generation
- smart meters/smart grids
- energy efficiency policies
- price responsiveness

⁴³⁶ For a more detailed treatment of the reasons to reconcile system level and spatial demand forecasts, see ACIL Allen Consulting, *Connection point forecasting: A nationally consistent methodology for forecasting maximum electricity demand: Report to Australian Energy Market Operator*, 26 June 2013, pp. 43–45.

⁴³⁷ ACIL Tasman, *Victorian Electricity Distribution Price Review: Review of maximum demand forecasts: Final report*, Prepared for the Australian Energy Regulator, 19 April 2010, p. 7.

- demand management initiatives
- electric cars.

Regular review of demand forecasting approaches

NSPs should review their demand forecasting approaches on a regular basis. The review should ensure that the NSP appropriately collected and used data inputs and that the demand forecast approach meets the forecasting principles.

The review should also focus on past forecasting performance and consider the possible causes of any divergence of historical maximum demand from the forecasts.⁴³⁸ The causes of the divergence could relate to factors such as differences between forecasts of explanatory variables and actual values, or because of issues with the models' specification.⁴³⁹

Summary of expected data requirements

This section sets out the information that we require to assess demand forecasts. These information requirements apply to both DNSPs and TNSPs. DNSPs already provided some of this information in RINs for previous determinations. TNSPs did not traditionally provide some of this information through the submission guidelines. However, they provided the information as part of their regulatory proposals, or in response to our requests during determinations.

Historical demand data

We require NSPs to provide the following historical maximum demand data for system and spatial demand at 10 per cent and 50 per cent PoE (in megawatts (MW) and megavolt amperes (MVA)):

- raw coincident maximum demand (including date, time and temperature)
- raw non-coincident maximum demand (including date, time and temperature)—for spatial demand only
- weather corrected coincident maximum demand (including date, time and temperature)
- weather corrected non-coincident maximum demand (including date, time and temperature)—for spatial demand only
- power factors
- coincidence factors.

Demand forecast data

We require NSPs to provide the following demand forecast data for system and spatial maximum demand at 10 per cent and 50 per cent PoE in MW and MVA:

- coincident peak demand
- non-coincident peak demand—for spatial demand
- power factors

⁴³⁸ We discussed this issue in the 'accuracy and unbiasedness' forecasting principle.

⁴³⁹ ACIL Allen Consulting, *Report to Australian Energy Market Operator: Connection point forecasting: A nationally consistent methodology for forecasting maximum electricity demand*, 26 June 2013, p. 8.

- coincidence factors—for spatial demand only

NSPs must describe the relationship between their 10 per cent PoE and 50 per cent PoE demand forecasts. Where a NSP uses 90 per cent (or other) PoE demand forecasts as inputs to its capex forecast, it must detail the relationship between those demand forecasts and the 10 per cent PoE and 50 per cent PoE demand forecasts.

NSPs must also demonstrate how the demand forecast data specified in this section reconciles with the demand forecast data that they provide for the augex model (section B.1).

System demand forecast models and other information

Top down forecasts are often in the form of econometric models, which NSPs must provide in their proposals. To assess the system demand forecast, we require the NSPs' system demand forecast model or models, and supporting documentation.

System demand forecast models

NSPs must provide (preferably in Excel format) the model or models that produce their top down demand forecasts, including any proprietary models. The model(s) should clearly separate inputs and calculations that relate to historical data from those that relate to forecast data. If a NSP performs sensitivity tests, then it should include those tests in separate tabs or files from the main top down demand forecast model.

NSPs raised concerns that publishing proprietary models, or providing them to external parties, would be a disincentive for consultants to develop and improve such models. They also noted practical limitations (file size and software requirements, for example) on providing their models for publishing.⁴⁴⁰ We consider transparency to be vital in the determination process. As we discussed previously, we must be satisfied expenditure forecasts reflect a realistic expectation of the demand forecast.⁴⁴¹ This necessarily requires us to assess the approach NSPs use to make those forecasts, including models.

In situations where disclosure will cause detriment to the NSP, we and the NSP would ideally agree at the F&A stage on a situation that enables a transparent assessment of its top down demand forecasting approach. We will have regard to our confidentiality guidelines when discussing such issues.⁴⁴²

Supporting documentation

NSPs must provide documentation that describes and supports its top down demand forecasting model(s). These documents must describe:

- sources for input variables (historical and forecast)
- model derivation (functional form)
- model explanatory variables. NSPs should describe why they included some and excluded other potential explanatory variables. Potential explanatory variables include:

⁴⁴⁰ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 5.

⁴⁴¹ NER, clauses 6.5.6(c)(3), 6.5.7(c)(3), 6A.6.6(c)(3) and 6A.6.7(c)(3).

⁴⁴² We are developing the confidentiality guidelines. Our website contains more information: www.aer.gov.au/node/18888.

- macroeconomic factors, including:
 - gross state product
 - gross domestic product
 - population
- electricity prices
- air conditioner penetration
- temperature variables, including:
 - average temperatures, including weights if applicable
 - maximum and/or minimum temperatures, as relevant
- embedded generation/solar photovoltaic uptake.

If NSPs rely on judgement to produce top down demand forecasts, we expect them to keep relevant information that supports that judgement and clearly identifies how it affected the forecasts.

NSPs should also provide documentation setting out the processes for reviewing their demand forecasting approaches, and the findings of those reviews. NSPs should describe changes to their demand forecasting approach from the previous determination.

If a NSP does not provide the information that we require to assess the demand forecast, then we will likely use information sources that are available to us at the time of the determination.

Bottom up forecast models and other information

NSPs that use models to produce spatial demand forecasts should provide information consistent with the requirements for top down forecast models (noting the explanatory variables in the models may differ at the spatial level compared to the global level). We also expect NSPs to keep relevant information that supports any use of judgement to produce spatial demand forecasts. Relevant supporting evidence includes:

- data on new connections
- connection enquiries and applications. We require quantitative information on the percentage of enquiries and applications that proceed historically
- documentation on land releases, building approvals and so on
- historical growth rates at the connection point
- load movements.

B.2.2 Reasons for the proposed approach

Our proposed demand forecast assessment approach is broadly similar to our approach in past determinations. The main change is that we are formalising the best practice demand forecasting principles that will guide our demand forecast assessments. A principles-based approach is appropriate because NSPs may reasonably use various approaches (including inputs, assumptions and models) to produce demand forecasts. In addition, demand forecasting is not a precise science

and so approaches will likely change over time as NSPs introduce refinements and improvements. The best practice demand forecasting principles in section B.2.1 apply to demand forecasting generally despite the heterogeneity and dynamic nature of forecasting approaches.

The information requirements specified above will ensure we can focus on assessing demand forecasts rather than on requesting such information during determinations.

The NER did not (and do not) contain guidance on assessing demand forecasts other than referring to a subjective test that we be satisfied forecasts reasonably reflect a realistic expectation of demand.⁴⁴³ We therefore had flexibility in making our demand forecast assessments in past determinations. We require such flexibility because, as noted, NSPs may use different approaches to produce their demand forecasts. On the other hand, this flexibility meant our assessment approach was ad hoc, which introduced some uncertainty for stakeholders. The lack of formal guiding principles (and associated information requirements), to our demand forecast assessment approach meant NSPs supported their demand forecasts with material that varied greatly in content, quality and rigor. As such, requesting further information from a NSP consumed time during our determination process.

In addition, NSPs often rely on the judgement of planning engineers to produce demand forecasts at the spatial level. This reliance is not inappropriate because demand forecasting at the lower levels requires detailed knowledge of factors that affect demand growth in the service area. These factors include town planning, subdivision approvals and land releases, and contact with major customers. The use of judgement, however, is not transparent and therefore not replicable if a NSP does not support it with appropriate evidence. It is not appropriate for us to accept expert judgement 'on trust'.⁴⁴⁴ Setting out our expectations that NSPs would provide evidence to support their use of judgement would ensure spatial forecasts are rigorous and replicable.

Confidentiality

In past determinations, many NSPs provided top down demand forecasts that their consultants produced using proprietary models. They did not provide those models on intellectual property grounds. In some cases, they provided minimal information on the models, such as outlines of the modelling process. The proprietary models thus prevented a rigorous assessment of demand forecasts. We could not assess important factors such as the model's functional form, the inputs and assumptions, and the testing and validation procedures that demonstrated the model's fit with explanatory variables.

A lack of transparency hinders an open and fair assessment of a NSP's demand forecast. While organisations that produce such proprietary models may be reputable, with experience and expertise in modelling, it would be inappropriate for us to take their forecasts 'on trust'. We must consider whether a NSP's expenditure forecast reasonably reflects a realistic expectation of the demand forecast. We cannot do this effectively without assessing the model and the underpinning assumptions. We will discuss and resolve confidentiality issues with NSPs during the framework and approach process.

⁴⁴³ NER, clauses 6.5.6(c)(3), 6.5.7(c)(3), 6A.6.6(c)(3) and 6A.6.7(c)(3).

⁴⁴⁴ AER, *Final decision: Powerlink transmission determination 2012–13 to 2016–17*, April 2012, p. 69.

Transitional issues

This section outlines issues that may have implications for the final version of the Guidelines, which we must publish on 29 November 2013.⁴⁴⁵ It also covers developments that may affect demand forecast assessments in future determinations. These issues and developments have implications for our demand forecast assessments and/or the way in which NSPs develop their forecasts. Either way, we will still apply the assessment principles in section B.2.1 when assessing NSPs' demand forecasts.

Australian Energy Market Operator's development of a demand forecasting approach

On 23 November 2012 SCER agreed to a comprehensive package of reforms to address concerns about rising electricity prices.⁴⁴⁶ In December 2012 the Council of Australian Governments (COAG) endorsed these reforms.⁴⁴⁷ In light of changing demand patterns, SCER agreed to task AEMO with developing demand forecasts that we may use to inform future determinations.⁴⁴⁸

AEMO is conducting a program to enhance its demand forecasting capabilities at the transmission level.⁴⁴⁹ Its demand forecasting approach will produce both system level forecasts and connection point forecasts. This program runs parallel to the consultation period for our draft and final Guidelines. AEMO published its demand forecasting approach for transmission connection points on 26 June 2013 (having published its approach for system level forecasting in 2012, updated in July 2013).⁴⁵⁰ It will produce the first tranche of demand forecasts under this approach for New South Wales and Tasmania in 2014, then other TNSPs thereafter.

Currently, AEMO is not conducting a program to develop demand forecasting approaches at the distribution level.⁴⁵¹ AEMO's current focus is to build its capability in developing forecasts at the transmission connection point level. Once it has completed this program, AEMO will liaise with us to determine whether it should similarly develop its capacity at the distribution level. We support AEMO's current program to enhance its demand forecasting capabilities because it will provide an alternative view of future demand. We will consider AEMO's forecasts as a significant input to our demand forecast assessments. Depending on the circumstances of the determination, and the findings of our assessments, we may use AEMO's demand forecasts for various purposes—for example, when performing sensitivity tests on a NSP's demand forecasts. Alternatively, we may use AEMO's forecast as the substitute demand forecast if our assessment indicates it, rather than the NSP's forecast, best reflects NER requirements. The weight we place on AEMO's demand forecast will likely change over time as AEMO's forecasting models and approaches improve.

We encourage all spatial and system level forecasts to reconcile (as per the principles in section B.2.1). We encourage NSPs to reconcile spatial forecasts with top down forecasts they consider reasonable, noting that AEMO produces independent forecasts, and is looking to improve its work in this area. Given AEMO's role, we would find benefit in understanding the reasons the NSP did not consider AEMO's forecasts to be suitable for reconciling spatial forecasts. This may assist AEMO in developing its forecasting approaches, and would inform our own demand forecast assessments.

⁴⁴⁵ NER clauses 6.4.5(a) and 6A.5.6(a) require that we publish the Guidelines. Transitional rules 11.53.4 and 11.54.4 set the date for its publication.

⁴⁴⁶ www.aemc.gov.au/market-reviews/completed/differences-between-actual-and-forecast-demand-in-network-regulation.html (accessed 8 May 2013).

⁴⁴⁷ www.scer.gov.au/workstreams/energy-market-reform/ (accessed 8 May 2013).

⁴⁴⁸ SCER, *Electricity: Putting consumers first*, December 2012, p. 13.

⁴⁴⁹ www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting (accessed 27 June 2013).

⁴⁵⁰ AEMO, *Executive summary: Connection point forecasting*, 26 June 2013, pp. 1–2.

⁴⁵¹ AEMO's regional forecasts for TNSPs may be consistent with DNSP demand at connection points.

Publication of consultations on connection point and zone substation data rule change

The National Generators Forum (NGF) requested that AEMO publish half hourly demand data, by connection point, across the NEM. The NGF indicated these data will provide market participants with enhanced information on changing demand patterns in the NEM, facilitating generation planning and investment decisions.⁴⁵² AEMO is currently developing a business case to determine the feasibility of the connection point data proposal. It will further consult with stakeholders between July and December 2013 on aggregation criteria.⁴⁵³

On 26 April 2013, the AEMC started its consultation on a related rule change request by the NGF. The request seeks a new requirement on DNSPs under the NER to annually publish historical electricity load data for their networks at the zone substation level.⁴⁵⁴ It seeks to introduce an additional requirement for DNSPs in the 'distribution annual planning report' process.⁴⁵⁵ If the data the DNSPs provide are robust, then the rule change is likely to provide benefits including better modelling of the key determinants of electricity demand changes at the sub-system level.⁴⁵⁶ We expect such analysis will help our demand forecast assessment, particularly of DNSPs.

Energy Networks Association's climate change adaptation project

The ENA is developing an industry approach to support the capacity of its members in managing climate risk and resilience across core network business activities.⁴⁵⁷ The project also aims to ensure consistency in how NSPs factor climate change risk in future network investment decisions.⁴⁵⁸

We understand NSPs may use the approach arising from the project as part of their demand forecasting processes. To the extent that NSPs do so, we will likely still apply the assessment principles in section B.2.1 when assessing the effects of the approach on NSPs' demand forecasts.

B.3 Replacement expenditure forecast assessment

This section discusses clause 4.1 of the Guidelines, which sets out the AER's approach to assessing the replacement expenditure (repex) component of a NSP's capex forecast.

Repex is the non-demand driven expenditure for the replacement of an asset with its modern equivalent, with the timing of the replacement linked to the age and or condition of the asset.⁴⁵⁹ This is a material component of NSPs' forecast expenditure, generally accounting for 30–60 per cent of network capex.⁴⁶⁰

⁴⁵² www.aemo.com.au/Consultations/National-Electricity-Market/Open/Proposal-to-publish-Connection-Point-Demand-Data (accessed 7 May 2013).

⁴⁵³ AEMC, *Consultation paper: National electricity amendment (Publication of zone substation data) Rule 2013*, 26 April 2013, p. 7.

⁴⁵⁴ www.aemc.gov.au/electricity/rule-changes/open/publication-of-zone-substation-data.html (accessed 7 May 2013).

⁴⁵⁵ NER, schedule 5.8.

⁴⁵⁶ AER, *AER submission on AEMC consultation paper — Publication of zone substation data rule (ERC0156)*, 24 May 2013, p. 1.

⁴⁵⁷ The ENA is the peak national body representing gas distribution and electricity transmission and distribution businesses throughout Australia. www.ena.asn.au/about-us/ (accessed 21 June 2013).

⁴⁵⁸ www.ena.asn.au/policy/innovation/climate-change-adaptation/ (accessed 21 June 2013).

⁴⁵⁹ AER, *A Guide to the repex model*, July 2011, p. 7.

⁴⁶⁰ AER analysis.

B.3.1 Our proposed approach

Our repex forecast assessment approach will remain largely the same as the approach we have used in recent determinations, which involves assessing:⁴⁶¹

- information supporting the NSP's building block proposal
- benchmarks and NSPs' historical actual and expected capex
- replacement expenditure modelling
- detailed project review.

The following sections discuss our assessment techniques for trend analysis and repex modelling. For discussion of how we use the more general techniques see chapter 4.

Trend analysis of actual and forecast capex

We will continue to consider a NSP's actual and expected repex for preceding regulatory control periods. We undertake trend analysis of the forecasting performance of NSPs by comparing the actual and forecast trends for each NSP's repex. Where a deviation from the historical trend is justified, we use the information provided by the NSP to assess this. Changes in NSP obligations (for example, changes in NSPs' safety obligations, or the introduction of restrictions on CO₂ emissions) could provide a feasible reason for deviating from historical repex levels.

A major feature of an incentive based regulatory framework is the regulated firm should achieve efficiency gains whereby actual expenditure is lower than the forecast. However, the regulator must ensure the forecasts adopted are accurate and well substantiated. Differences between actual and forecast repex could be the result of efficiency gains, forecasting errors or some combination of the two. Where there are concerns about the ability of NSPs' forecasting models to predict reliably future asset replacement requirements, we have applied our repex model instead to forecast the required repex for the relevant expenditure items.⁴⁶²

Past trend analysis suggests NSPs' repex forecasts systematically overestimate capex.⁴⁶³ This analysis has shown NSPs spend significantly less than their initial forecast or the repex allowance as part of the determination process. Further we have observed that actual repex follows a gradual increasing trend.⁴⁶⁴

We will continue undertaking trend analysis alongside assessing NSPs' policies, procedures, and forecasting methodologies when considering if the proposed expenditure forecast is justified.

⁴⁶¹ A 'determination' refers to both distribution determinations and transmission determinations under chapters 6 and 6A, respectively, of the NER.

⁴⁶² AER, *Draft decision: Victorian electricity distribution network service providers distribution determination 2011–15*, June 2010, p. 338.

⁴⁶³ AER, *Draft decision: Victorian electricity distribution network service providers distribution determination 2011–15, Appendix I - Benchmarking* June 2010, pp. 61–65.

⁴⁶⁴ AER, *Draft decision: Victorian electricity distribution network service providers distribution determination 2011–15, Appendices*, June 2010, pp. 61–62.

Replacement expenditure model

We used replacement expenditure modelling techniques in our recent determinations. In September 2009 we engaged Nuttall Consulting to develop a replacement capex forecasting model (repex model). Nuttall Consulting produced a high-level probability based model that forecasts repex for various asset categories based on their condition (using age as a proxy) and unit costs.⁴⁶⁵ We then compared NSP forecasts with the repex model outputs to identify and target expenditure that required detailed engineering and business case review.

Box 3 The repex model

The repex model combines data on the existing age and historical rates of replacement across categories of different assets, and assumptions about the probability of failure (or replacement prior to failure), to forecast replacement volumes into the near future.

For a population of similar assets, the replacement life may vary across the population. This can be due to a range of factors, such as its operational history, its environmental condition, the quality of its design and its installation. Asset age is used as a proxy for the many factors that drive individual asset replacements.

In developing our repex model, it was decided the model should have similar characteristics to those used by the UK regulator, Ofgem. For this form of model, the replacement life is defined as a probability distribution applicable for a particular population of assets. This probability distribution reflects the proportion of assets in a population that will be replaced at a given age.

The shape of the probability distribution should reflect the replacement characteristics across the population. Our repex model, similar to the Ofgem approach, assumes a normal distribution for the replacement life. The repex model also calibrates assumptions with respect to recent replacement history.

From a regulatory point of view, this form of replacement modelling provides a useful reference to assess regulatory proposals because it allows for high level benchmarking of replacement needs. It is a common framework that can be applied without the need to rely entirely on intrusive data collection and detailed analysis of the asset management plans of particular NSPs. That said, no model of this kind could predict with certainty when an asset will fail or need to be replaced. In addition to forecasting volumes for an individual NSP, the model can facilitate the benchmarking of assumed replacement lives and the unit cost of replacement.

We will use the repex model to assess NSPs' asset life and unit cost trends over time, as well as comparing them to NSP benchmarks. In instances where we consider this shows a NSP's proposed repex does not conform to the capex criteria, it may be used (in combination with other techniques) to generate a substitute forecast.

⁴⁶⁵ AER, *Final decision: Aurora Energy Pty Ltd, 2012–13 to 2016–17*, 30 April 2012, p. 124.

We anticipate over time that comparing the actual and forecast volumes will provide a better understanding of changes in asset condition, failure rates, impacts of reliability outcomes and loading for the network. We consider the repex model will be less applicable to transmission determinations initially than to distribution determinations. This is because replacement for most TNSPs involves asset groups with unique projects that are lower in volume and higher in value than those for DNSPs. For these asset groups, we will collect more aggregated asset data, which are less comparable and predictable.

Using repex model outputs, we will examine benchmarks of unit costs for asset categories under each asset group.

Table B.1 Asset data benchmarks

Distribution	Transmission
\$/unit—Poles by each asset type	\$/unit—Steel towers for each asset type
\$/unit—Pole top structures for each asset type	\$/unit—Pole structures for each asset type
\$/unit—Overhead conductors for each asset type	\$/unit—Conductors for each asset type
\$/unit—Underground cables for each asset type	\$/unit—Transmission cables for each asset type
\$/unit—Services for each asset type	\$/unit—Substation switch bays for each asset type
\$/unit—Transformers for each asset type	\$/unit—Substation power transformers for each asset type
\$/unit—Switchgear for each asset type	\$/unit—Substation reactive plant for each asset type
\$/unit—Public lighting for each asset type	\$/unit—Communications for each asset type
\$/unit—SCADA and protection for each asset type	\$/unit—Other assets for each asset type
\$/unit—Other for each asset type	\$/unit—IT for each asset type

Source: AER analysis.

Summary of expected data requirements

Repex is categorised into asset groups, which, for comparability, are then separated into smaller asset categories according to characteristics that indicate the asset’s function (see section B.3.2). Each asset in a NSP’s network serves a discrete purpose or set of functions, hence we consider defining asset categories by function provides objectivity in asset type classification across NSPs.

This gives us a defined set of high-level functional asset categories for benchmarking. NSPs will be expected to report expenditure, as well as the number of assets installed and disposed of in each category annually. The following tables provide an overview of the standardised data we will collect from DNSPs and TNSPs respectively. Asset groups for DNSPs and TNSPs are identified then subcategorised (where relevant/ possible) into voltage and rating as a common characteristic across several asset categories.

Table B.2 DNSP Replacement expenditure asset groups

Poles	Transformers
Pole top structures	Switchgear
Overhead conductors	Public lighting
Underground cables	SCADA and network control
Services	Other

Source: AER analysis.

Table B.3 TNSP Replacement expenditure asset groups

Steel towers	Substation power transformers
Pole structures	Substation reactive plant
Conductors	Communications
Transmission cables	Other assets
Substations switch bays	IT

Source: AER analysis.

We will require NSPs to report network information annually, as well as part of its regulatory determination proposal.⁴⁶⁶ We currently require DNSPs to report the following information in their annual RINs about their network assets:

- mean replacement asset life (years)
- standard deviation of the mean replacement asset life
- replacement unit cost (\$ nominal)
- total number of asset failures during the regulatory year
- total quantity (number) of each asset type that was commissioned in each financial year.

Age profile

The age profile is the volume and respective ages within each asset category at a static point in time.⁴⁶⁷ We have designed asset categories that enable NSPs to provide historical volumes that reconcile to their internal planning documents and models. We consider NSPs should be able to back cast this information from their depreciation schedules and asset registers.

Mean life and standard deviation

Once a NSP generates an age profile for an asset category, it must provide the mean and standard deviation replacement life of each asset type. In circumstances where the standard deviation is unknown, it can be set to the square root of the mean life.⁴⁶⁸

⁴⁶⁶ NER, clause. 8.7.2.

⁴⁶⁷ AER, *A guide to the repex model*, July 2011, p. 14.

⁴⁶⁸ AER, *A guide to the repex model*, July 2011, p. 14.

Unit costs

NSPs will be required to present unit costs for each asset type (split by direct labour, direct materials, contract and allocated overhead), describing the estimation method used, and ensuring they reconcile to their own internal cost recording systems. For capex direct costs, we will require NSPs to disaggregate direct costs into direct labour, direct materials, contract and allocated overhead, as set out in section B.8.1. Estimates of forecast unit costs for each asset type will be on a reasonable basis, using the most robust data. We consider NSPs will be able to estimate these unit costs accurately.

B.3.2 Reasons for the proposed approach

As noted above (section B.3.1), our proposed approach to assessing repex remains largely unchanged from our current approach. The key changes are using the repex model more widely (including in transmission determinations), and benchmarking standard lives and unit costs of replacement.

We also expect to engage with each NSP about issues such as using age to approximate asset condition, and ways to encourage greater conformity in how NSPs classify expenditure to different asset categories.⁴⁶⁹ Measuring and reporting replacement volumes over time, and understanding the components of each NSP's forecast, is expected to deliver important information.

We do not consider providing this information will impose a significant burden on NSPs. There will be some costs incurred in developing and aligning existing information reporting arrangements to new standardised categories as well as providing the prescribed unit cost breakdown. However, we consider these will be outweighed by the expected benefits of more effective assessments of this important expenditure category. We applied the repex model in recent distribution determinations that enabled us to consider the rate and average cost of replacement for individual DNSPs, using their observed behaviour as an indication for the future.

The most material repex issues we consulted on were the data inputs to the repex model (particularly the choice of asset categories) and how the repex model functions.

Asset categories for repex model

United Energy broadly agreed with the asset categories for the repex model outlined in the Issues Paper. However, it considered the model's outputs would need careful interpretation before they could be used as even an indicator of the need for further more detailed engineering analysis. It also questioned the extent to which the repex model can capture all of the drivers of the replacement decision for a specific business.⁴⁷⁰

In our workshops, DNSP representatives noted they record information at different levels of detail, and that in some instances they could only derive or estimate some of the data required to populate the repex model. They considered this was particularly relevant for smaller networks because statistical indicators become harder to derive.⁴⁷¹ We do not consider this is a major issue provided the derivation is clear and well documented.

⁴⁶⁹ AER, *A guide to the repex model*, July 2011, p.14.

⁴⁷⁰ United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues Paper*, March 2013, p. 15

⁴⁷¹ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Transmission)*, 8 March 2013, pp. 3–4.

Before the release of the draft Guidelines, we circulated our initial proposed asset categories and subcategories for the repex model as a ‘straw man’ for stakeholder comment.⁴⁷² We received responses from the ENA, JEN and Grid Australia on what they consider is the best way to standardise asset categories.⁴⁷³ The NSPs stated that asset groupings should be at a high enough level to cover all NSPs, but allow NSPs discretion to add subcategories that reflect their unique circumstances. They further noted that NSPs are unlikely to be able to provide all required data at auditable quality and that RIN requirements will need to reflect those limitations.⁴⁷⁴

As mentioned above (section B.3.1), categories are based on the asset’s function. NSPs must report asset types consistently so we can compare volumes, asset lives and relative expenditure of replacing certain asset types. NSPs will be required to map their existing asset registers to the AER’s asset categories.

Table B.4 and Table B.5 explain common data requirements across asset categories, namely maximum voltage and ampere rating. We anticipate consulting further with stakeholders on these characteristics in the coming months.

Table B.4 Common characteristics across TNSP asset category classifications

Driver	Maximum voltage	Ampere rating
Measured by	~33 kV	Low Medium High
	~66 kV	
	~132 kV	
	~220 kV	
	~330 kV	
	~500 kV	
AER reasoning	Where voltage is a key driver of an asset's design specification, we consider this can materially impact cost. We consider the voltage classifications above capture the changes in design specification.	Rating indicates an asset's capacity. Required capacity drives design specification. We require NSPs for each asset to classify low, medium and high ampere rating bands and categorise assets accordingly
NSPs view	Materiality considered on an asset-by-asset basis.	Materiality considered on an asset-by-asset basis.

Source: AER analysis and Grid Australia, *Better Regulation program: replacement and augmentation expenditure categories*, 26 April 2013.

⁴⁷² AER, 'Repex & augex strawman proposal', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

⁴⁷³ In response to AER, 'Repex & augex strawman proposal', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

⁴⁷⁴ ENA, *Response to AER's straw man proposal: Asset categorisation with the augex and repex models*, 26 April 2013; JEN, *Asset replacement and augmentation modelling: JEN observations on the AER's proposed asset categorisation*, 22 April 2013; Grid Australia, *Better Regulation program: replacement and augmentation expenditure categories*, 26 April 2013.

Table B.5 Common characteristics across DNSP asset category classifications

Driver	Maximum voltage	Ampere rating
Measured by	< 1 kV	Low Medium High
	≥ 1 kV and <11 kV	
	~ 22 kV	
	~33 kV	
	~66 kV	
	~132 kV	
AER reasoning	Where voltage is a key driver of an asset's design specification, we consider this can materially impact cost. We consider the voltage classifications above capture the changes in design specification. For comparability purposes, this is the most appropriate distinction to draw acknowledging that distinguishing voltage by the type of network segment the asset is serving (that is, split by high, low or sub-transmission) is also common.	Rating indicates an asset's capacity. Required capacity drives design specification. We require NSPs for each asset to classify low, medium and high ampere rating bands and categorise assets accordingly

Source: AER analysis; ENA, *Response to AER's straw man proposal: Asset categorisation with the augex and repex models*, 26 April 2013, JEN, *Asset replacement and augmentation modelling: JEN observations on the AER's proposed asset categorisation*, 22 April 2013.

Table B.6 and Table B.7 below show the characteristics we consider to materially drive the function of each of the asset categories, and so our proposed detailed data requirements for each category of asset. We have included an outline of our reasoning and any NSP commentary on our proposed data requirements.

Table B.6 Replacement expenditure asset categorisation for DNSP asset groups

Asset Group	Common characteristics		Additional characteristics			AER Reasoning
Poles	Voltage	✓	Driver	Material	Staking	A pole is designed to be of a certain height and strength level. We consider the maximum voltage the pole carries is the main determinant of its height, it affects how much clearance from the ground any conductors or furnishing requires. The strength level required of the pole influences the material used in its construction.
	Rating	x		Measured By	Wood Concrete Steel	
<p>NSP View: ENA consider categorising poles by maximum voltage and material type appropriate however standardising the location is difficult given NSPs unique operating environments. JEN in its response to the AER's straw man showed the ability to break down poles by the voltage, material and location</p>						
Pole top structures	Voltage	x	Driver	Purpose		Pole-top structures highly specialised nature means there is likely little design consistency within a network let alone across networks. The purpose of the structure determines design complexity as well as the required materials. As the complexity of the structure increases it is likely the input costs will be higher.
	Rating	x		Measured By	Intermediate Angle Strain	
<p>NSP View: A number of DNSPs do not keep data specifically related to pole top structures, as these structures are managed as an intrinsic part of the pole asset. For these DNSPs, expenditure on pole top structures is likely to be either capex for a single asset replacement, or it will be included as part of a pole replacement or line re-conductoring project. Including pole top structures as part of either the conductor group or the pole group is, however, likely to cause difficulty in establishing the correct replacement unit cost based on historic project expenditures. JEN provided information on its pole top structures in accordance with the AER's straw-man categories.</p>						
Services	Voltage	✓	Driver	Customer Type	Complexity	Services are works conducted on service lines, we consider the characteristics which drive the cost of performing the service are dependent on the voltage of the connection, the customer type and connection complexity.
	Rating	x		Measured By	Residential Commercial & Industrial Sub-division	
<p>NSP View: ENA considered that services should only be split by overhead and underground asset types. We consider that this does not allow a sufficient break-down for comparing different service costs across DNSPs.</p>						

Transformers	Voltage	✓			As implied by the name this asset type transforms a higher voltage into a lower voltage, therefore maximum voltage and maximum continuous rating dictate transformer design. The local area where the transformer is installed can also materially impact the design specified, and we consider mounting type is the best proxy for this. We will work with the ENA to refine the bands appropriate to this category.
	Rating	✓			
NSP View: The ENA in its submission in response to the AER's straw-man categories provided possible sub-categories making the distinction by voltage and maximum continuous rating. ENA also provided commentary on the different bands associated with these drivers.					
Switchgear	Voltage	✓	Driver	Switch function	The switch function determines the components of the switch and therefore the design specification. The AER expects DNSPs to report sub-categories for differing equipment types such as isolators, re-closers and, circuit breakers. To accurately assess the total switchgear a NSP will need detailed knowledge of all of the assets in that category
	Rating	x	Measured By	Isolator Circuit breaker Switch Fuse	
NSP View: ENA combined zone and distribution switchgear into a single "switchgear" group, noting that It is recognised that some DNSPs may wish to model separately different categories of switchgear such as isolators, re-closers and, circuit breakers. Sub-categories serve this purpose. JEN provided information on its distribution switchgear in accordance with the AER's straw-man categories and offered commentary on suggested changes					
Overhead conductors	Voltage	✓	Driver	Insulation type	An overhead conductor is designed for a particular maximum continuous rating and voltage, driving the conductor's material type and diameter. Furthermore segments of the network's conductors may require insulation from nearby vegetation. We require NSP's to classify their conductors by those factors that materially impact costs.
	Rating	✓	Measured By	Bare Covered / ABC	
NSP View: We received no specific comments from NSP's regarding overhead conductors in response to the AER's straw man categories. The ENA proposed that it be dealt with as part of a singular 'Lines' category.					
Underground cables	Voltage	✓	Driver	Type	An underground cable is designed for a particular maximum continuous rating and voltage, driving the cable material type and diameter. Furthermore segments of the network's travel under bodies of water, clearly affecting the cost of replacement. We require NSP's to classify their underground cables by those factors that materially impact costs.
	Rating	✓	Measured By	Submarine Non-Submarine	

NSP View: The ENA in its submission responding to the AER's straw man categories provided underground cables split by type (submarine and non-submarine) and voltage.

Public lighting	Voltage	x	Driver	Road Type	Asset Type	Public lighting requirements are determined by the environment that DNSP's networks operate in. We consider splitting NSP's public lighting assets by type and road type allows sufficient comparability.
	Rating	x	Measured By	Major road Minor road	Luminaires Brackets Lamps Poles/columns	
NSP View: We received no specific comments from NSP's regarding public lighting in response to the AER's straw man categories.						

SCADA and network control	Voltage	x	Driver	Function		We consider SCADA and protection to be a highly function based asset category. We note the methods deployed by NSP's for this category facilitates reporting of assets by high-level function. As we observe below for transmission, the trend is towards network-based equipment with control and data collection systems built into the equipment. This suggests that a better category for the future may be an operational IT category. The ENA proposal is reasonable in addressing legacy systems. We will work with the ENA to address this emerging shift in technology.
	Rating	x	Measured By	Protection relays	Substation meters	
				Data unit	Copper pilot cable	
				Radio equipment	Fibre optic pilot cable	
				Radio towers		

NSP View: The ENA submitted a breakdown of SCADA and Protection in response to the AER's straw man categories which is reflective of the above breakdown.

Other assets	Voltage	x				We consider this category is broad by definition. We require NSPs to report any asset types which do not explicitly fit into any of the above-mentioned asset categories. We consider it likely to be difficult to compare this group across NSP's and it will be considered on a case-by-case basis. We acknowledge the breakdown provided by ENA and require NSP's to report against these assets.
	Rating	x				
NSP View: The ENA submitted a breakdown of asset types that fit this category in response to the AER's straw man categories.						

Source: AER analysis; ENA, *Response to AER's straw man proposal: Asset categorisation with the augex and repex models*, 26 April 2013, JEN, *Asset replacement and augmentation modelling: JEN observations on the AER's proposed asset categorisation*, 22 April 2013.

Table B.7 Replacement expenditure asset categorisation for TNSP asset groups

Asset Group	Common characteristics	Additional characteristics	AER Reasoning
Steel towers	Voltage ✓	Driver Circuit type	We accept the Grid Australia proposal as reasonable.
	Rating X	Measured By Single Multiple	
NSP View: Grid Australia’s submission in response to the AER’s straw man noted that steel tower strengths can vary depending on factors such as span length and size of conductor. This means that designs of individual towers will vary depending on the topographical situation.			
Pole structures	Voltage ✓	Driver Circuit type	We accept the Grid Australia proposal as reasonable.
	Rating X	Measured By Single Multiple	
NSP View: Grid Australia’s submission in response to the AER’s straw man noted that pole structures can include structures comprising a single pole or multiple (up to three) poles, depending on topographical situation. They suggested, regardless of the number of poles per structure, separating by voltage level and configuration (whether single or double circuit.)			
Conductors	Voltage ✓		We note that Grid Australia proposes injects an either/or categorisation. Adoption of rating as a head sub-category creates a linkage to actual service capability that may be compared across the NEM. However, our preference is to maintain the conductor type as a sub-category of conductor rating. This is because the replacement cost of assets is likely to be strongly influenced by the technical choices preferred by different service providers.
	Rating ✓		
NSP View: Grid Australia’s submission in response to the AER’s straw man noted that the separation of conductors from towers/poles would generally be a lower level of disaggregation than in TNSP’s asset registers. They suggested kilometres of conductors be reported by voltage level and either conductor type (for example, whether single, twin or quad conductor) or capacity (which will dictate conductor type)			

Transmission cables	Voltage	✓	Driver	Insulation type		We accept the Grid Australia proposal as reasonable.
	Rating	X		Measured By	Oil filled	
					XLPE	
				Etc.		
<p>NSP View: Grid Australia's submission in response to the AER's straw man noted that the AER proposes sub-categories by voltage and insulation type. They consider these sub-categories reasonable, but note that the population of cables at transmission voltages is small.</p>						
Substation switchbays	Voltage	✓	Driver	Insulation type	Switch type	The Grid Australia proposal would lead to a simple model structure for switchbays, assuming that TNSPs generally undertake bay-level replacement. However, the AER will need to consult with Grid Australia further on this matter to clarify both that assumption and how such a bay category can best be defined. If this approach were adopted then the AER would anticipate current transformers (CTs) and voltage transformers (VTs) to be captured in the bay specification.
	Rating	X		Measured By	Air break	
					Oil	Isolator/Disconnecter
				Gas	Surge Diverters	
<p>NSP View: Grid Australia's submission in response to the AER's straw man suggests that the switchbays category should not be disaggregated into equipment types, because lower level allocations are likely to be affected by "unit cost" variances and the data is likely to be not comparable across TNSP's over time. Grid Australia proposes that instead the substation switchbays category remain at the aggregate level. Substation switchbays should include current transformers and voltage transformers, which the AER's straw man has under secondary systems.</p>						
Substation power transformers	Voltage	✓				We accept the Grid Australia proposal as reasonable. Although we do not propose to record the cooling type category in our reporting templates.
	Rating	✓				
<p>NSP View: Grid Australia's submission in response to the AER's straw man considers the proposed sub-categorisation by nominal voltage level, capacity and cooling type is reasonable.</p>						

	Voltage	✓	Driver	Function	We accept comparisons of reactive plant based on individual units are not sufficiently informative to support benchmarking. To address this, we consider information to be submitted should relate to the capacity of these items.
	Rating	✓	Measured By	SVCs	
				Capacitors Oil filled reactors	
<p>NSP View: Grid Australia's submission in response to the AER's straw man considers the proposed sub-categorisation of SVCs, capacitors, synchronous condensers and reactors by voltage level is reasonable, but notes that:</p> <ul style="list-style-type: none"> ▪ The function and capacity of SVCs differ on an individual basis, which makes comparison non-sensible ▪ Only one TNSP in the NEM has synchronous condensers, and if replaced these may be replaced with different technology. There is therefore little value in this sub-category for other TNSPs. ▪ The reactors sub-category should refer only to oil-filled reactors, and not to smaller air-cooled reactors which are used occasionally and not comparable 					
Communications	Voltage	X			It has become apparent that there is an evolution of protection, control and communications technology that makes separation of the elements of communications and control from broader systems difficult. The AER will consult further with Grid Australia on this category.
	Rating	X			
<p>NSP View: Grid Australia's submission in response to the AER's straw man suggests that the proposed sub-categories of SCADA, optical fibre and other communications are difficult to quantify for these sub-categories, because:</p> <ul style="list-style-type: none"> ▪ Optical fibre installations are partly managed under transmission line asset management, to the extent that bearers are a component of transmission lines ▪ The sub-category "other communications" is too broad and diverse to quantify sensibly on a common basis. ▪ Grid Australia suggested that the communications category should not be disaggregated into sub-categories. 					
Other assets	Voltage	X			This category might have applied to miscellaneous items such as plant and equipment. However, given those assets are diverse and of variable and generally short lives, we accept this category is not needed for general analysis.
	Rating	X			

NSP View: Grid Australia's submission in response to the AER's straw man suggests that the units are difficult to quantify for this category and is seeking clarification from the AER on the purpose of this category in terms of what it is intended to measure.

Source: AER analysis and Grid Australia, *Better Regulation program: replacement and augmentation expenditure categories*, 26 April 2013.

Issues with the repex model

Application of modelling outputs

NSPs queried whether the repex model could produce a range, rather than a point, forecast.⁴⁷⁵

The AER commissioned the repex model to provide an indication of areas of a NSP's regulatory proposal requiring deeper investigation. We exercise our discretion in screening a NSP proposal for expenditure that differs markedly from the repex model, which indicates in practice we apply the repex model using a range. However, we must decide on a single figure in a regulatory determination, and producing a range of outputs in the repex model would introduce uncertainty to the process. We agree with user groups that producing a range would also encourage NSPs to argue for the top of the range.⁴⁷⁶ We do not consider the repex model will be the only technique we use to set expenditure. We will liaise with consultants to examine the engineering and economic reasoning the NSP used to develop the expenditure forecast for each project and whether it accords with the capex criteria. We recognise that the uncertainty associated with estimates generated by repex model is strongly linked to sample size, this is in accordance with standard statistical theory. Based on the reaction from NSPs during recent consultation, we will also consider how best to present and apply model outputs as part of our capex assessment to avoid debates around spurious accuracy.

Using age as the sole proxy for asset condition

NSPs noted that they replace most assets based on condition, rather than age. Further, the repex model relies on age-based probabilistic modelling techniques and does not consider other drivers of replacement.

We acknowledge that, prior to calibrating, the repex model does not take account of replacement drivers other than asset age. As we noted above, we commissioned the repex model as a screening tool. This means we will pay close attention to condition-based reports where significant divergence between the age-based forecast and condition-based assessments exists. During a regulatory determination we expect NSPs to furnish us with condition data to demonstrate why age is not an appropriate approximation in particular cases. We would also be examining this data where the repex model indicates a NSP is efficient. Having said that, not all of a NSP's repex forecast is based on condition, particularly with regard to high-volume, low-value assets where condition-based monitoring would not be feasible. We are also considering the development of asset health indices that may assist in standardised analysis of replacement needs.

Model sensitivity to inputs

In previous determinations, NSPs' consultants noted that the use of a normal distribution as the basis for modelling remaining life is inappropriate. They stated that the Weibull distribution is widely acknowledged in reliability engineering literature as more appropriate. We agree that the Weibull distribution is an alternative type of statistical distribution commonly used in reliability engineering and failure analysis. The Weibull distribution is theoretically appropriate but we note that there are a number of practical considerations that favour using the normal distribution.

Firstly, the differences between the two distributions when observed in practical situations of moderate to large samples of assets tend to be small. It is possible to discuss this effect in considerable academic detail without significantly affecting the practical outcome. One possible

⁴⁷⁵ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

⁴⁷⁶ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

reason why the difference between the two approaches tends to be small is based in statistical theory. When sampling a population of assets with a particular statistical distribution (i.e. not normally distributed), the sample of that other distribution will tend to assume a normal distribution. This effect is generally attributed to the Central Limit Theorem as applied to the normal distribution. Parsons Brinckerhoff (PB) conducted analysis on behalf of a regulated firm.⁴⁷⁷ PB considered that the calibration process in the repex model means that for a given mean asset life, a normal distribution and a Weibull distribution are similar. It went on to note, however, there is divergence after the mean, but this effect was not substantial. This outcome is consistent with our understanding of this issue.

Another major issue is the availability of accurate data. Few businesses will have access to the historical data necessary to calculate the shape and scale parameters that are important preconditions to forming an accurate Weibull distribution. However, we consider NSPs should have the information to form an accurate normal distribution, but acknowledge that in the past there have been some gaps in the information available to the NSP. For benchmarking purposes it is important to be able to compare a firm with its peers. In practice, this means that all firms should be on the same basis. Thus, given that many NSPs will lack the ability to calculate a Weibull distribution and it will be costly and time consuming to do so, the normal distribution approach is preferable. It will minimise unnecessary cost and allow comparisons between NSPs.

Overall there is an immaterial difference between using the normal and Weibull distribution to model the age profile of network assets. We do not consider changing the assumption on the asset life distribution will materially improve the robustness of the repex model.

Model calibration process

NSPs noted calibrating the repex model was an issue during the Victorian distribution determination. NSPs queried why the repex model required calibration, and what the principles behind calibration are.⁴⁷⁸

We consider the repex model should focus on actual asset lives as observed in practice by each NSP, not theoretical asset lives (for example, asset lives for tax purposes or 'standard' asset lives, as are often quoted by asset managers). In the most recent Victorian distribution determinations, recalibration of the model sought to reconcile historical data on asset replacement with the expected replacements for an asset of a given nominal asset life. When this adjustment converged to a consistent value the forecast was recalculated based on the revised asset lives up to the end of the regulatory control period. Further, we considered that the most recent year(s) of capex data for the Victorian DNSPs did not appear to reflect the regulatory control period or typical asset management processes, requiring multiple adjustments for model calibration proposes.

We note that where a NSP has sufficiently detailed records and can directly calculate actual observed mean life and standard deviation, the need for recalibration will be substantially reduced or eliminated. The Victorian DNSPs did not have these data available.

Availability of input data

User representatives requested the input and output data for the repex models be published during a determination process, enabling them to conduct independent analysis. However, NSPs were concerned users would take the repex model outputs as deterministic. Therefore, the AER should

⁴⁷⁷ AER, *Final decision: Aurora distribution determination Aurora Energy Pty Ltd, 2012–13 to 2016–17*, 30 April 2012

⁴⁷⁸ AER, 'Meeting summary - repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream - Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

clearly qualify the results of these models. Further, NSPs should have the opportunity to explain outputs of the repex model.⁴⁷⁹

We consider the best outcome is populating the repex and publishing it prior to NSPs submitting their regulatory proposals. NSPs could then be mindful of the results of the modelling when preparing their proposals.

Estimation techniques

During workshops, DNSP representatives raised the repex model requires a better definition of “unit rate” because a replacement activity (such as “pole replacement”) may represent a number of distinct activities (for example, replace a cross-arm versus replace the pole itself). The definitions need to make clear what direct and indirect costs are to be included or excluded. It was also noted, however, that aggregation of such unit costs averages out such differentials, and that the AER should therefore focus its investigation where more aggregated unit cost differentials are material.⁴⁸⁰

We consider that to be able to make meaningful comparisons in unit rates we need information on the inputs NSPs use to generate the asset. These can be broadly specified in terms of direct labour, direct materials, contract and allocated overheads. We will require NSPs to provide unit rates by disaggregating direct labour and direct materials costs as well as contract and allocated overhead costs.

Accounting for differences in operating environments

In workshops, DNSP representatives queried how the repex model accounts for differences in operating environments. They cited the example of wood poles deteriorating at different rates in different environments.

We consider it inappropriate to compare NSPs’ replacement expenditure without considering their operating environments. In developing our data requirements, we reflected on commentary provided in workshops and submissions on the key factors affecting replacement needs. Even so, we recognise the limitations that will be inherent in any standardised approach, particularly one involving benchmarking. The use of sub-categories within an asset category is a practical response to this concern. Breaking down major categories into sub-categories can help demonstrate these differences whilst still allowing the overall expenditure category to be benchmarked. Asset categories should be large enough to gather like assets in sufficient volumes to make comparisons meaningful but should also aid the identification of the ‘pressure points’ in a proposal. While we have defined a set of sub categories (i.e. asset types) for each group of assets in the model, NSPs are free to add further sub categories as long as they are mapped under the existing asset types in the model.

We will rely on NSPs to identify any differences between their own historical unit costs or replacement volumes, and those of their peers, that reflect any factor not already accounted for in our data set. We will also consider requesting this type of information in our Guidelines and regulatory information instruments. A key example is the importance of asset condition assessments. We are considering the most appropriate way to obtain this information and to reflect it in our benchmarking assessments. In the short term we will continue to assess forecast repex within the context of any asset management plans NSPs submit to substantiate the forecast repex. More generally, in assessing

⁴⁷⁹ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Transmission)*, 8 March 2013, p. 2.

⁴⁸⁰ AER, 'Meeting summary - DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream - Replacement and demand driven augmentation (Transmission)*, 8 March 2013, p. 3.

asset management plans, we will primarily seek to determine if the decisions made are likely to lead to the lowest life cycle cost in present value terms.⁴⁸¹

Transitional and implementation issues

We used the repex model in our most recent distribution determinations, but we acknowledge the model has not been used for all NSPs.⁴⁸² Further, we expect stakeholders will identify issues over time. Applying the repex model in future determinations will familiarise stakeholders with it and aid in resolving any potential issues.

Some issues may only be identified with large scale implementation. We can resolve such problems only through experience and if we encounter issues, we will attempt to resolve them as they arise. Depending on the nature and extent of the issue, we may place less emphasis on the analysis of the repex model in a determination.

It is likely we will use the repex model as a first pass model in future determinations, in combination with other assessment techniques.⁴⁸³ Initially, we will likely review proposed repex forecasts for all asset categories in detail, even those the repex model suggests are at reasonably efficient levels. This will help us to understand when we can rely on the repex model as a first pass model (and when we cannot).

B.4 Customer-initiated capex forecast assessment

This section discusses clause 4.3 of the Guidelines, which sets out how we propose to assess, as part of our revenue determinations, NSPs' forecast capex for providing customer initiated services.

Customer-initiated services prepare the electricity network to support the connection of new and existing network customers. They comprise of the following activities:⁴⁸⁴

- new customer connections (standard control / negotiated services for DNSPs and TNSPs, respectively)
- other services (alternative control for DNSPs):
 - meter installation and maintenance associated with a new customer connection
 - augmentation of the shared network resulting from a new customer connection and by customer request
 - public lighting installation and maintenance associated with a new customer connection
 - fee based and quoted services common across DNSPs
 - miscellaneous fee based and quoted services that are not attributable to the above service categories.

We recognise that the terms of customer-initiated services are negotiated between TNSPs and their customers and are therefore unregulated. However, to the extent that the provision of a negotiated

⁴⁸¹ See section 4.4.6 of the Explanatory statement for details on how we assess life cycle costs.

⁴⁸² AER, *Final decision: Aurora Energy Pty Ltd, 2012–13 to 2016–17*, 30 April 2012 and AER, *Final decision: Victorian distribution determination, 2011–15*, 29 October 2010.

⁴⁸³ See section 1.3.3 of the Explanatory statement.

⁴⁸⁴ Consistent with past processes, we will classify activities as standard or alternative control services in our framework and approach paper.

service gives rise to expenditure which may be attributable to a regulated service, we will use our assessment tools to determine whether such expenditure is efficient.

For DNSP connections capex we will consider gross expenditure requirements, that is, prior to accounting for customer contributions. We also note that charges for customer-initiated works have a direct customer impact and our assessment of these works needs to be considered in light of this.

B.4.1 Our proposed approach

Our proposed approach is to standardise the reporting of cost data for customer initiated works, to streamline the regulatory process and minimise regulatory burden for NSPs. We will do this through:

- designing uniform data reporting requirements, to group comparable customer initiated work activities for DNSPs
- using data of comparable customer initiated works in category and economic benchmarking analysis. This may be used to better target detailed engineering analysis to inform our determinations of forecast expenditure requirements for NSPs
- indicating the likely cost data we would require TNSPs to report for use in detailed engineering reviews.

The Guidelines outline DNSPs' data reporting requirements in relation to our assessment techniques. Generally, we consider benchmarking analysis is suitable for those customer initiated works for which expenditure is recurrent and volumes of particular activities reflect a similar scope of works over time or across NSPs.

Initially, we will not impose detailed reporting requirements on TNSPs to provide cost data for customer-initiated works. Reporting requirements for TNSPs may change over time as information provided in the course of detailed engineering review reveals the possibility for us to use benchmarking and/or trend analysis.

We will continue our approach of using trend analysis in setting expenditure allowances for the DNSPs' provision of customer-initiated services. However, we will also increasingly rely on new assessment techniques, in particular, category analysis benchmarking, economic benchmarking and more targeted detailed engineering reviews. Using category analysis and economic benchmarking, we will measure the relative efficiency of the DNSPs in providing customer-initiated services across the NEM. We will use those techniques also as screening tools, to select expenditure items for detailed engineering review. Furthermore, we will continue to use the engineering review for assessing the scale and scope of capital works, and whether forecast expenditure is efficient.

We will primarily use detailed engineering reviews to assess the expenditure requirements of TNSPs for providing customer-initiated works.

Summary of expected data requirements

General Information reporting requirements

We will require NSPs to report historical and forecast input costs of customer-initiated works consistently. NSPs should disaggregate input costs into material and labour categories, with the estimation method detailed. We would expect forecast input costs to be estimated on a reasonable basis, using current and robust data which reflects the expected economic cost of customer-initiated works. Historical costs should be measured as costs that are incurred 'on the job' and are reconcilable

to the NSPs' internal cost recording systems. NSPs must report historical cost data in a way that is consistent over time. Without consistent reporting, we cannot conduct benchmarking analysis (that is, a like-for-like comparison of customer initiated works over time).

Data provided to us in regulatory proposals must be reconciled to the NSPs' internal planning documents. It must also reconcile to any models that NSPs provide as part of the regulatory process or use to justify their proposals. We may not accept, or may place low weight on, information sources that we find to be irreconcilable or inaccurate.

Classification of customer-initiated services

Data classifications of customer-initiated works will only apply to DNSPs. We acknowledge the scope and scale of customer-initiated works differ among the DNSPs, and we can use analysis such as benchmarking only for making like-for-like comparisons. To address difficulties in distinguishing efficiencies from genuine differences in each works' specifications, we have developed a screening procedure to compare those customer initiated works that are similar in nature across DNSPs. This procedure organises different types of customer initiated work into comparable groupings with common:

- customer type voltage
- connection type
- meter type and
- location of public lighting works.

We will collect cost data for categories of customer initiated works with a view to grouping a variety of works with similar costs, as outlined in Table B.8. We also expect the DNSPs to recast historical data into the categories presented in Table B.9 to Table B.12.

Table B.8 Classification of connections capital work categories

Customer type	Connection type
Residential installations	Simple type connection (LV)
	Complex type connection (LV)
	Complex type connection (HV)
Commercial and industrial installations	Simple type connection (LV)
	Complex type connection (LV)
	Complex type connection (HV)
Subdivision (residential/commercial and industrial)	Complex type connection (HV)
Embedded generation installations	Complex type connection (LV)
	Complex type connection (HV)

Notes: HV and LV are abbreviations for high voltage and low voltage, respectively.

Table B.9 Metering capital work categories

Meter type	Cost category
Meter model xx	Meter purchase cost
	Meter testing
	Meter investigation
	Special meter reading
	New meter installation
	Meter replacement

Table B.10 Public lighting capital work categories

Location (NSP to nominate)	Cost category
Suburb/aggregation of suburbs	Installation of new luminaires
	Replacement of existing luminaires
	Maintenance/repair of public lighting assets

Table B.11 Common fee-based and quoted services categories

Service	Cost category
Fee-based services	Energisation
	De-energisation
	Re-energisation
	Truck Visit
	Wasted truck visit
Quoted services	General line worker
	Design/Survey
	Administration

Table B.12 Miscellaneous fee-based and quoted services categories

Service	Cost category (DNSP to nominate)
Fee-based services	Category xx
Quoted services	Category xx

Description of customer-initiated work activities

In addition to requiring cost data, we will require the TNSPs and DNSPs to describe their overall customer initiated capital works program by allocating customer-initiated expenditure into the categories presented in Table B.13.

Table B.13 High level descriptors of customer initiated capital works

Customer type	Descriptor metric ^(a)
Information required for all customer types (that is, residential/commercial and industrial/subdivision/embedded generation connections)	Total number of connections by location
Information required for all customer types	Total number of meter replacements by meter type (%)
	Connection Voltage (only relevant for TNSP)
	Connection Rating (only relevant for TNSP)
Information required for all customer types	Urban (%)
Information required for all customer types	CBD (%)
Information required for all customer types	Rural (%)
Information required for all customer types	Multidwelling (%)
Information required for all customer types	Material (%)
Information required for all customer types	Labour (%)
Information required for all customer types	Underground (%)
Information required for all customer types	Overhead (%)
Information required for all customer types	Single phase (%) (only relevant for DNSPs)
Information required for all customer types	Multi phase (%) (only relevant for DNSPs)
Information required for all customer types	Transformer (%)

Note: % denotes the percentage of total expenditure related to a customer type (for example, the percentage of customer initiated expenditure for residential consumers).

Specification of materials and labour costs

Reporting of these categories will apply to TNSPs and DNSPs. We expect both DNSPs and TNSPs to disaggregate customer-initiated capex into the cost categories of direct labour, direct materials, contract and allocated overhead costs. This breakdown is common across all expenditure category analysis and relates to our approach to addressing capitalisation and cost allocation issues (see section B.8.2 for further details).

TNSPs reporting of these cost categories will be used as part of our detailed engineering review. The categories of labour and materials should be selected to list the most significant drivers of cost for customer initiated works, to compare a NSP's efficiency relative to that of other NSPs.

Direct costs – Definition and guidance on estimation

Direct costs are costs that can be identified and are specific to each customer-initiated work activity. We require that NSPs estimate an average of direct costs across their suite of projects for each classification of customer-initiated works. For example, a NSP may perform 1000 simple connections

over the regulatory period – we would require a NSP to provide an average estimate of direct cost categories for the 1000 simple connections.

Overhead costs – Definition and guidance on estimation

Overhead costs are network and corporate costs that cannot be directly attributed to a particular category of service, activity or project, but which are typically allocated across several categories of service, activity or project. Overhead costs should be allocated to services, activities or projects in accordance with each NSP's cost allocation methodology (see section B.8 for further discussion).

B.4.2 Reasoning for proposed approach

We developed expenditure reporting categories for customer-initiated works to address problems that we encountered in assessing NSPs' past revenue proposals. Our proposed approach will significantly improve our assessments in future determinations by:

- aligning the categorisation of expenditures across NSPs, increasing the scope for benchmarking
- allowing a more transparent consideration of changes between historical and forecast unit costs, and the rates of activities/volumes in a NSP's supply of customer initiated works. We will thus be able to rely more on the capex incentive framework, by using historical behaviour to challenge forecast expenditure proposals
- streamlining the assessment process, whereby regulatory proposals submit the same information. That is, NSPs will provide data that reconcile to their forecasting models and planning documents. In past determinations,⁴⁸⁵ we had to perform these reconciliations at the expense of spending time analysing the information provided. Further, NSPs were burdened with information requests during determinations, which added to their regulatory costs.

The reasoning for selecting categories is discussed in the following sections.

Classifications of customer-initiated works

Our proposed classifications will only apply to DNSPs. The classifications will highlight cost differences, and we will use them in combination with other assessment techniques to determine the efficiency of a DNSP's expenditure forecast. We consider category benchmarking analysis is suitable for those customer initiated works that have recurrent expenditure and include the same input costs over time. For customer-initiated works that are less typical, we may still use category benchmarking to assess elements of input costs that are consistent over time and across DNSPs. If input costs are not conducive to benchmarking analysis, then we may require a detailed engineering review to assess expenditure.

Connections classifications

We chose these classifications to distinguish connection projects in terms of complexity. They accord with some DNSPs' existing connections classifications, while capturing the common cost structures faced by the DNSPs when performing a variety of connection works. The following project specifications largely account for cost differences between different connection types, and we will use them to implement benchmarking analysis:

⁴⁸⁵ AER, *Powerlink transmission determination: Final decision*, April 2012, p. 104; AER, *Queensland distribution determination: Final decision 2010–11 to 2014–15*, May 2010, pp. 100–3; AER, *Final distribution determination, Aurora Energy, 2012–13 to 2016–17*, April 2012, p. 26.

- simple type connection—a low voltage (LV) connection of new/existing customers to existing network infrastructure with a single span of wire and not requiring augmentation to the shared network
- *complex type connection*—a low voltage / high voltage (LV/HV) connection of new/existing customers that is not a simple type connection and may involve the installation of a HV isolator and, a distribution transformer. It may require alterations to upstream shared assets, with large extension to existing network infrastructure.

Meter classifications

We will allow DNSPs to specify the types of meter that they are using to provide meter services. The meter type and voltage requirements of the customer will dictate the costs of meter purchasing and the meter related maintenance activities. We expect the number of meter installations should be consistent with the overall volume of connections. We note that a number of cost categories within Table B.9 are alternative control services. For the purpose of benchmarking, we consider it useful to have all meter activities reported together. This does not reflect our position on the classification of services as either standard or alternative control. A DNSP should use the categories in Table B.9 to report its costs from providing meter services.

Public lighting classifications

We will allow DNSPs to specify the location of public lighting, which we expect is the main determinant to explain the difference in costs of performing public lighting services. For the purpose of benchmarking, we consider it useful to have all public lighting activities reported together. This does not reflect our position on the classification of services as either standard or alternative control. A DNSP should use the categories in Table B.10 to report its costs from providing public lighting services.

Common fee based and quoted services

These categories consist of those fee-based and quoted services which are commonly provided by DNSPs. To the extent that these categories are comparable, we will use benchmarking analysis to assess the efficiency of DNSPs in providing these services. Where benchmarking analysis cannot be performed, a detailed engineering review or trend analysis may be used in the assessment of these costs. We have aligned our reporting requirements with categories of the DNSPs' existing alternative service schedule of charges to ensure consistency with current reporting, in order to minimise regulatory burden. We have developed consistent definitions so that the efficiency of DNSPs' providing these services can be compared across the NEM. A DNSP should use the categories in Table B.11 to report its costs for providing common fee-based and quoted services.

Miscellaneous fee based and quoted services

These categories consist of fee-based and quoted services which tend to be relatively less material and may also not consistently be provided by DNSPs across the NEM. For these services, we consider that benchmarking analysis will have only limited use, if any, to assess the efficiency of DNSPs. We will primarily rely on detailed engineering review and, or trend analysis to assess DNSPs' provision of these services. A DNSP should use the categories in Table B.12 to report its costs for providing these services.

Controlling for a NSP's unique circumstances

To meaningfully measure the relative efficiency of each NSP, we must consider customer-initiated capex in light of the unique circumstances of the NSP's operating environment. As such, we identified

factors (Table B.13) that may explain the difference in cost and will provide us with an overall snapshot to explain how the costs of providing these works have changed over time. We will use descriptor categories as a high level indicator of the scope and scale of customer-initiated works to be undertaken over the regulatory period, and in assessing the comparability of DNSPs for category benchmarking analysis. For each service (connections, metering and public lighting), if relevant, the DNSPs must disaggregate the percentage of their total expenditure related to customer initiated works that relates to each category in Table B.13. The DNSPs' reporting requirements for the high level descriptors may change over time as we refine our assessment approach to reviewing DNSPs' expenditure forecast requirements.

We consider Table B.13 caters to the DNSPs' and TNSPs' existing abilities to disaggregate total expenditure into categories of customer- initiated works. In submitting forecasts of customer-initiated works for past revenue proposals, DNSPs used similar categories to disaggregate their proposed expenditure.

The following subsections justify our selection of those factors.

Density

Reporting of this category will apply to TNSPs and DNSPs. We will consider the density factor by using the CBD, urban and rural and multi-dwelling connection categories to measure the time and distance travelled to perform customer initiated works. Time and distance is expected to have an impact on the labour cost involved in providing customer-initiated works.⁴⁸⁶ The density factor will also be useful for us to measure the distance between existing network infrastructure and new infrastructure associated with proposed customer initiated works. A greater distance may mean the NSP needs to expand and more significantly develop its network to increase coverage to the new area, which would increase its construction requirements and therefore the materials cost of the proposed customer initiated works.⁴⁸⁷

Connection type

Reporting of this category will apply to TNSPs and DNSPs. Underground and overhead connection types are required for us to distinguish the physical characteristics of customer connections works. Underground connections require the construction of a service pit and may involve the breaking and re-instatement of ground surface. Overhead connections may necessitate the installation of a pole, or simply the addition of wiring to an existing pole. The difference between underground and overhead connections will significantly affect the cost configurations of connection works and the materials and labour input costs.

Additionally, TNSPs will be required to specify the voltage and rating of each of their proposed connection projects.

Location

Reporting of this category will apply to TNSPs and DNSPs. The NSPs should group connection types by nominating location groupings that generalise the cost of performing customer-initiated works in a certain locale. Where relevant, a NSP should specify the location groupings based on unique features that influence the different cost of performing works there as opposed to other locations. The groupings will capture the main factors which influence the complexity of customer-initiated works and

⁴⁸⁶ SP AusNet, *Customer Connection Guide*, 11 March 2008, p. 6.

⁴⁸⁷ Aurora, *Customer initiated capital works (CICW) management plan*, March 2011, pp. 10–11; AEMO, *Victorian annual planning report: Appendix A - New investors guide*, 24 June 2011, pp. 12–13.

therefore the labour and material input costs. Based on an examination of several NSPs' practices, we expect that the following factors will be considered by NSPs decisions to group locations:⁴⁸⁸

- the ground surface condition
- topography of the network terrain
- customer demographics
- accessibility of customer sites
- location of works relative to existing network infrastructure.

We require NSPs to report the number of new connections, meter installations/replacements and public lighting works by each location which they identify as uniquely influencing cost.

Input costs

Reporting of this category will only apply to DNSPs. We will require direct material, direct labour, contract and allocated overhead costs to compare the direct unit costs of customer-initiated capital works. We acknowledge that the definitions of various input unit costs for customer initiated works must be consistent across DNSPs. Further, while we do not intend to prescribe how the DNSPs are to estimate the costs of customer-initiated works, we consider the DNSPs should generally justify their estimations based on the most current unit cost and volume data and cost drivers. They should support that justification with documentation of the models used and the data underlying those models.

We consider that the scope and scale of the same customer-initiated works may be different for each DNSP and could therefore make works incomparable between DNSPs. In particular, DNSPs may use varying proportions of the same material and labour inputs, or different inputs, which are not comparable. To take account of these differences, we require DNSPs to disaggregate proportions of input costs used for providing customer-initiated works. As such, DNSPs must report the percentage of expenditure for materials and labour categories for new connections (for residential, commercial and industrial and subdivision connections), meter installations/replacement (for each meter type) and public lighting works. Additionally, DNSPs will be required to report the percentage of expenditure in relation to transformers used for connection works. We expect the cost of new connections metering activities will be significantly affected by the installation of a transformer as part of the connection. Finally, we also require DNSPs to disaggregate the percentage of connections which are single or multi-phase, as this will also affect the cost of connection and metering activities.

Transitional and implementation issues

Differences between transmission and distribution networks

We acknowledge the differences between customer-initiated works performed for distribution and transmission networks. In particular, the works for transmission networks typically:

- involve fewer projects, and ones that are performed less frequently, compared with distribution networks

⁴⁸⁸ Aurora, *Customer initiated capital works (CICW) management plan*, March 2011, pp. 10–11; AEMO, *Victorian annual planning report: Appendix A - New investors guide*, 24 June 2011, pp. 12–13; SP AusNet, *Customer Connection Guide*, 11 March 2008, p. 6.

- are larger and typically involve a higher cost per project, compared with distribution networks.

Grid Australia noted much of the equipment used by each TNSP is standard across different works (for instance, replacement, augmentation and connections works).⁴⁸⁹ To the extent that standard equipment is consistently used as an input to providing customer initiated services, we may use benchmarking analysis to assess the efficiency of costs incurred over time. Further, we acknowledge Grid Australia's submission to our issues paper that transmission services are very different from distribution network services as classified under the NER.⁴⁹⁰ Specifically, connection point works and extension works have a different meaning for transmission networks and can be classified as negotiated or non-regulated services. We do not propose to collect information on negotiated services and non-regulated services for TNSPs.

Feasibility of reporting and benchmarking of standardised expenditure

In their submissions to our issues paper, CitiPower/Powercor and SA Power Networks,⁴⁹¹ JEN,⁴⁹² Ergon Energy⁴⁹³ and the ENA⁴⁹⁴ noted the practical difficulty in designing reporting requirements that produce robust data that we can use to compare the NSPs' costs. In particular, it assumes a degree of network homogeneity that is difficult to achieve in terms of changing business processes to report cost data.

In developing the draft guideline, we considered the NSPs' current ability to disaggregate expenditure related to customer initiated capital works. Specifically, we had regard to:

- information that NSPs provided in past revenue proposals;
- publicly available information on the structuring of categories to determine customer fees and connection policies
- comments by NSPs at our workshops and in response to our issues paper.

In designing our reporting requirements, we considered the NSPs' existing ability to disaggregate categories of connection expenditure from capex forecasting models that they used to support previous revenue proposals. As such, we do not consider the data reporting requirements in our draft guideline are inconsistent with the NSPs' existing ability to disaggregate connection expenditure. Further, our reporting requirements are sufficient to address the deficiencies of the NSPs' current reporting requirements by generating data that is comparable across NSPs and allows us to reasonably compare customer-initiated works over time. We chose classifications and defined connection types that we can use to compare connection works across NSPs. We also designed a template for the DNSPs to report descriptor metrics that will explain scale, scope and locational differences across DNSPs, and allow us to account for the unique circumstances of each DNSP.

Submissions made by the ENA,⁴⁹⁵ Ergon Energy,⁴⁹⁶ CitiPower/Powercor and SA Power Networks⁴⁹⁷ in response to our issues paper noted the NSPs do not categorise expenditure by basic connection,

⁴⁸⁹ AER, 'Meeting summary - Connections & customer driven frameworks for TNSPs', *Workshop 7: Category analysis work-stream - Connections and customer driven works (Transmission)*, 19 March 2013, p. 4.

⁴⁹⁰ Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper*, 18 March 2013, p. 33.

⁴⁹¹ CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, p. 2.

⁴⁹² JEN, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 11.

⁴⁹³ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 14.

⁴⁹⁴ ENA, *Submission on AER expenditure forecast assessment guidelines issues paper, Attachment B*, 8 March 2013, p. 2.

⁴⁹⁵ ENA, *Submission on AER expenditure forecast assessment guidelines issues paper, Attachment B*, 8 March 2013, p. 3.

⁴⁹⁶ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 14.

extension and capacity upgrades. In many cases, a connection may involve all three components. To account for this matter, we propose to report a category of complex type connections, which may include augmentation of upstream assets and additions made to network infrastructure. Additionally, a number of DNSPs distinguish between simple/basic connections (which involve no augmentation to the upstream network) and complex connections (which involve augmentation to the upstream network) in their respective customer connections guidelines.⁴⁹⁸ Our categorisation of simple and complex connections should thus accommodate the way in which a number of DNSPs categorise connection types.

The ENA highlighted the increase in 'generation connections' may lead to the need to separately record the connections expenditure associated with distributed generation.⁴⁹⁹ We thus included a separate category to record connections expenditure associated with embedded generation in our reporting template.

Accounting for key cost drivers

The ENA,⁵⁰⁰ Ergon Energy,⁵⁰¹ CitiPower/Powercor and SA Power Networks⁵⁰² highlighted the cost of new connections differs significantly according to the connection's purpose, size and location. Additionally, JEN,⁵⁰³ Aurora Energy⁵⁰⁴ and the MEU⁵⁰⁵ considered a clear cost difference exists between overhead and underground connections.

We chose the factors in Table B.13, as well as for asset works captured in repex and augex data requirements, with regard to NSPs' comments (in workshops) according to the most significant elements which determine the cost of customer initiated services, namely:

- whether a connection is a replacement or new connection
- whether a connection is an underground or overhead connection
- the voltage of the connection
- the location of the connection
- maximum demand relative to asset capacity.⁵⁰⁶

⁴⁹⁷ CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B - Category analysis*, 15 March 2013, p. 2.

⁴⁹⁸ www.unitedenergy.com.au/customers/your-electricity/electricity-connections/basic-new-connections.aspx, Accessed 6 August 2013; Aurora Energy, *Connections policy*, 1 July 2012, pp. 8–9; SA Power Networks, *Network tariff and negotiated services manual, No. 18*, June 2013, pp. 53–56.

⁴⁹⁹ ENA, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, p. 3.

⁵⁰⁰ ENA, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper, Attachment B*, 8 March 2013, p. 2.

⁵⁰¹ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 14.

⁵⁰² CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B - Category analysis*, 15 March 2013, p. 2.

⁵⁰³ JEN, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 11.

⁵⁰⁴ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 17.

⁵⁰⁵ Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 11.

⁵⁰⁶ AER, 'Meeting summary - Connections & customer driven frameworks for TNSPs', *Workshop 7: Category analysis work-stream - Connections and customer driven works (Transmission)*, 19 March 2013, pp. 2–3; AER, 'Meeting summary - Connections & customer driven frameworks for DNSPs', *Workshop 9: Category analysis work-stream - Connections and customer driven works (Distribution)*, 20 March 2013, pp. 2–3.

Additionally, DNSPs considered the costs of connection works for distribution networks are also influenced by:

- the location of connection works (e.g. CBD, rural or urban locations)
- the scale of a new development (that is, the size and density of subdivisions / newly constructed buildings)
- the reliability demands of the customer
- whether a connection is simple or complex.

TNSPs did not support releasing any costing data at a highly disaggregated level, in case such data is used in benchmarking costs to make misleading conclusions that do not account for the differences between TNSPs.⁵⁰⁷

DNSPs indicated they could not provide accurate historical data detailing unit rates for key cost inputs of connection works.⁵⁰⁸ DNSPs also noted they do not record the individual costs of connection works, but could provide data at an aggregate average level of costs and could include key input costs associated with this work.⁵⁰⁹ We assessed DNSPs' disaggregation of connection works from previous regulatory proposals, and consider our proposed categorisation in Table B.8 to be not particularly onerous. For this reason, we consider our information reporting requirements will not place excess regulatory burden on the DNSPs beyond their existing reporting obligations.

Aurora considered subcategories of connections expenditure should be designed according to the repex model.⁵¹⁰ Our categories of material cost inputs of connection works are consistent with the repex model, as in Box 3 (section B.3.1). Grid Australia indicated recording unit costs may be difficult for TNSPs, which may be unable to record equipment costs separately from installation, transport and other costs (particularly for work contracted out on a supply and install basis).⁵¹¹ We consider each NSP will be able to report material and labour cost inputs for customer initiated works in varying detail. We expect NSPs should be able to sufficiently disaggregate the expenditure of customer initiated works to list the cost of the most significant inputs, such as those mentioned in Box 3. Our expectation is supported by Grid Australia's comments (at workshop seven) that TNSPs have internal price estimation manuals based on past costs and sometimes use external parties to come up with estimates for cross-checking purposes.⁵¹²

Accounting for gifted assets

NSPs must disclose to us the estimated quantity of gifted assets constructed by developers and third parties. We will consider gifted assets when making revenue determinations and performing benchmarking analysis to assess the efficiency of a NSP's costs.

⁵⁰⁷ AER, 'Meeting summary - Connections & customer driven frameworks for TNSPs', *Workshop 7: Category analysis work-stream - Connections and customer driven works (Transmission)*, 19 March 2013, p. 4.

⁵⁰⁸ AER, 'Meeting summary - Connections & customer driven frameworks for DNSPs', *Workshop 9: Category analysis work-stream - Connections and customer driven works (Distribution)*, 20 March 2013, p. 4.

⁵⁰⁹ AER, 'Meeting summary - Connections & customer driven frameworks for DNSPs', *Workshop 9: Category analysis work-stream - Connections and customer driven works (Distribution)*, 20 March 2013, p. 4.

⁵¹⁰ Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 17.

⁵¹¹ AER, 'Meeting summary - Connections & customer driven frameworks for TNSPs', *Workshop 7: Category analysis work-stream - Connections and customer driven works (Transmission)*, 19 March 2013, p. 4.

⁵¹² AER, 'Meeting summary - Connections & customer driven frameworks for TNSPs', *Workshop 7: Category analysis work-stream - Connections and customer driven works (Transmission)*, 19 March 2013, p. 4.

We note that some jurisdictions permit contracting of customer-initiated works to be performed by third parties. Where customer-initiated works are not undertaken by NSPs, we acknowledge that cost data may be unavailable for NSPs to report. In these instances, we do not require NSPs to report cost data for customer initiated works. DNSPs commented in workshops that where connection works are performed by contracted third parties, under a contestable framework, they will generally not have actual data on these works.⁵¹³ Additionally, TNSPs commented (in a workshop) that reporting of unit costs may be difficult for those works performed by third party contractors and will reflect the extent to which contractors disaggregate costing data.⁵¹⁴

Customer contributions policy

Customer contributions are payments by each customer connecting to the network, to ensure the connection costs are borne by the customer requesting the connection and not the entire customer base. They represent the difference between the connection cost (including necessary augmentation of the upstream network) and the present value of the forecast network use of service charges that the DNSP expects to recover over the life of the connection.

We will assess the prudence of customer contributions forecasts to ensure they represent unbiased estimates. To adequately assess forecasts of customer contributions, we require DNSPs to explain in detail how they estimated the average costs for connections. In particular, DNSPs will be required to submit their connection policy to us for approval in the course of a revenue determination, in accordance with part DA of chapter six of the NER. Further, DNSPs should explain the following key assumptions in their calculation of the network use of system charges:

- the expected life of the connection
- the average consumption expected by customers over the life of the connection
- any other factors that a DNSP considers influence the expected network use of system charge.

In past determinations, some NSPs provided detailed modelling to explain their estimation of customer contributions over classes of customer connections. We consider this approach provides transparency that allows us to better assess DNSPs' proposed customer contributions. We expect all DNSPs to provide such modelling in future revenue proposals.

B.5 Non-network capex forecast assessment

This section discusses the contents of clause 4.4 of the Guidelines, which sets out our approach to assessing the non-network component of a NSP's capex forecast. This section explains our proposed methods to assess capex on non-network assets, along with the data that we require for our assessment. It also considers supervisory control and data acquisition (SCADA) and network control capex.

NSPs' regulatory proposals can involve significant non-network capex, particularly IT and property related expenditure. Key issues in our past assessments included: proposals' lack of economic

⁵¹³ AER, 'Meeting summary - network inputs', *Workshop 8: Economic benchmarking techniques work-stream - Network inputs*, 20 March 2013, p. 4.

⁵¹⁴ AER, 'Meeting summary - Connections & customer driven frameworks for TNSPs', *Workshop 7: Category analysis work-stream - Connections and customer driven works (Transmission)*, 19 March 2013, p. 4.

justification for projects; an inability to benchmark expenditure across a business due to its different acquisition methods⁵¹⁵; and trend analysis issues due to changes in acquisition methods over time.

B.5.1 Proposed approach

Our assessment approach will remain broadly similar to our past approach. We will assess a NSP's expenditure forecasts and how these were developed with reference to key volume and cost drivers. We will also consider how forecast expenditure compares to past expenditure, and the economic justification for any step changes in expenditure. However, we propose to standardise capex categories and how expenditure input costs are recorded, to target projects more systematically for detailed review.

For our assessment, we propose to break non-network capex into the following categories:

- IT and communications capex
- motor vehicles capex
- property capex
- other capex
- SCADA and network control capex.

When assessing NSPs' forecast expenditures in these categories, we intend to focus on governance and asset management plans, the business cases underpinning expenditure, and the method used to develop the expenditure forecasts. We will use a combination of tools for our assessment, including trend analysis, cost–benefit analysis, benchmarking of costs, and detailed technical assessment.

While we will aim to assess overall governance processes and all asset management plans, we will likely assess only a sample of projects and their business cases. Often, we will undertake the assessments with the help of technical experts. The sampling process is likely to target higher risk and high cost projects, and may also consider a random selection of projects.

We prefer a revealed cost approach to assessing forecast expenditure that is relatively recurrent. When non-network capex is recurrent, we may examine the prior period's expenditure to determine whether it is an efficient base for the assessment of forecasts. In doing so, we may examine asset management plans, business cases and benchmark expenditure of other NSPs.

For assessing non-recurrent expenditure, we propose to primarily examine the NSP's economic justifications for that expenditure, including any underlying business cases and cost–benefit analyses. We expect to receive clear economic justification for all material expenditure.

For all categories of expenditure, NSPs should forecast recurrent expenditure using identified volume and cost drivers. Further, they should economically justify all material expenditure and identify all key cost drivers for both recurrent and non-recurrent expenditure.

Some costs are not incurred on a standalone basis—that is, NSPs incur costs for some items as part of a larger contractual arrangement. In this situation, we propose NSPs should report estimated costs allocated to expenditure categories, and they should clearly indicate the costs were incurred as part of

⁵¹⁵ For example, purchasing versus leasing, which is opex.

a package of supplied works/services. Further, NSPs should state any assumptions used to allocate costs. This information should allow us to understand which costs are genuinely incurred versus resulting from allocations within, or subsequent to, a supply contract.

Given all the information before us, we will consider whether the proposed expenditure in each non-network category appears efficient and prudent. When we find expenditure is not efficient and prudent, we may substitute our own values for expenditure, in the context of setting an overall efficient and prudent expenditure allowance for the business. When project sampling indicates a degree of inefficiency, we may extrapolate that finding across all similar projects.

The remainder of this chapter outlines further processes related to the individual categories of non-network capex and SCADA and network control.

Table B.14 Non-network capex data requirements

Major category	Sub category	Quantitative measures	Qualitative evidence
IT & communications	Recurrent (PC and other)	Number of employees	Economic justification for expenditure
	Non recurrent	Number of end users	
		Number of devices	
Vehicles - (Network/ non-network)	Cars	Number of vehicles	Economic justification for expenditure
	Light Commercial	Unit costs	
	Heavy commercial	Km travelled	
	Elevated platforms	Fixed and variable costs	
Buildings and property	Recurrent	Expenditure by key driver	Economic justification for expenditure
	Non-recurrent		
Other		Expenditure by key driver	Economic justification for expenditure
SCADA and network control		Expenditure by key driver	Economic justification for expenditure

B.5.2 Reasons for the proposed approach

We consider the proposed non-network expenditure categories reflect a reasonable breakdown of non-network capex. This breakdown includes separating SCADA and network control expenditure from IT and communications costs, because these expenditures have distinct cost drivers. Having NSPs report consistently under these categories should allow for better comparability of expenditure over time and across businesses. Further, these categories cover the key expenditure categories examined in past regulatory decisions, and we discussed them with stakeholders at workshops (who mostly accepted the categories).

Generally, we consider our current assessment processes are appropriate. With adequate data, they should allow simplified assessment of recurrent expenditure through trend analysis and more detailed assessment and technical review of more complex lumpy investments. The separation of recurrent expenditure from non-recurrent expenditure should improve our assessment of recurrent expenditure

via trend analysis. Further, greater standardisation of categories and cost inputs should facilitate improved assessment of forecasts via trend analysis and the benchmarking of a NSP's category costs against those of other NSPs.

Also, if NSPs provide more consistent asset management plans and business cases, then we should improve our assessment of the economic justifications for capex proposals. NSPs should improve how they justify and estimate their forecast expenditure by clearly and consistently linking forecast expenditures to cost drivers. In prior proposals, economic justification was often insufficient for us to conclude the proposed expenditure was efficient and prudent. This issue was particularly the case with step changes in expenditure that need to be economically justified and appropriately forecast.

Examination of total expenditure (opex as well as capex) should improve trend analysis and benchmarking for expenditure categories that are often undertaken using different procurement methods. Different procurement methods prevented effective benchmarking in previous regulatory decisions. NSPs supported us considering differences in procurement methods when examining forecast expenditure. They did not, however, support us looking at the finer contract details of individual lease and purchase arrangements.⁵¹⁶ Our proposed, standardised data reporting requirements do not capture this level of detail.

The following sections cover assessment issues related to each category of non-network capex.

Assessment of IT and communications capex

We propose to define IT and communications capex as non-network capex directly attributable to the replacement, installation and maintenance of IT and communications systems (excluding SCADA and network control systems). This category will include any common costs shared with SCADA and network control (for example, communications links). Including these common costs recognises that certain assets (for example, communication links) may be used for multiple purposes, and their separation is likely to be of limited value. It should result in more consistent reporting and improve both historical and benchmark comparisons of firm costs.

We intend to assess expenditure forecasts broadly in line with our past assessment techniques. In doing so, we expect to primarily use trend analysis, an assessment of business cases and asset management plans, and technical review. We may also benchmark costs relative to other NSPs costs, if appropriate.

We intend to assess IT and communications expenditure in combination. However, to the extent that communications expenditure has cost drivers distinct from those of IT expenditure, NSPs should separately identify those drivers. Further, they should break down IT and communications expenditure into relatively recurrent expenditure and other relatively less recurrent expenditure. Recurrent expenditure should include all hardware, software, licensing and support costs associated with personal computers, recurrent communications expenditure, and any other expenditure NSPs consider relatively recurrent in nature. As required, we will undertake a technical review of material IT and communications expenditure, particularly non-recurrent expenditure.

We propose NSPs report forecast opex and capex separately for this category, along with the combined total expenditure. NSPs should break down data by recurrent and non-recurrent forecast expenditure, as follows:

⁵¹⁶ AER, 'Meeting summary - Overheads, cost allocation, statutory accounting, and capitalisation policies', *Workshop 16: Category analysis work-stream - Overheads, cost allocation, statutory accounting, capitalisation policies (Transmission & Distribution)*, 8 May 2013, pp. 3–4.

- recurrent
 - personal computer expenditure (PCs, laptops, notepads etc.)
 - other, which may include costs associated with communications (mobile phone expenditure, fixed line external communications expenditure, two way radio expenditure etc.)
- non-recurrent.

The separation of recurrent and non-recurrent expenditure will better facilitate trend analysis and benchmarking of costs. Separately forecasting recurrent expenditure related to desktop computers is due to this expenditure having distinct identifiable cost drivers (namely, employee numbers).

During consultation, NSPs commented that any separation of IT from communications and detailed disaggregation of these categories may be difficult, given IT and communications services are often provided under bundled contracts.⁵¹⁷ We acknowledge the overlap between IT and communications expenditure, and that these services are often acquired together under contract. For these reasons, we propose to require NSPs to identify recurrent communications expenditure separately only when they can identify specific drivers for that expenditure. They would report the expenditure under 'other' recurrent expenditure, which may be most relevant to expenditure related to third party networks (microwave, fixed line, mobile, two way radio etc.). When NSPs enter bundled contracts, they should report both the overall costs and an estimate of the allocation to different categories (along with the basis of their method of allocation).

Assessment of vehicle related capex

We propose to define motor vehicle capex as non-network capex directly attributable to the purchase, replacement, and maintenance of motor vehicles assets, excluding mobile plant and equipment. We propose to assess vehicle related expenditure by examining the number and types of vehicle, and the cost per vehicle. Because vehicles can be leased or purchased, we may partly assess vehicle capex and opex by examining the total expenditure.

We propose to break down forecast vehicle expenditure into the following standardised vehicle classes:

- cars
- light commercial vehicles
- vehicle mounted elevated work platforms
- heavy commercial vehicles.

NSPs should forecast and historically record the following data for each vehicle class:

- a basic explanation of the volume and cost drivers
- the number of vehicles
- the average kilometres travelled

⁵¹⁷ AER, 'Meeting summary - Overheads, cost allocation, statutory accounting, and capitalisation policies', *Workshop 16: Category analysis work-stream - Overheads, cost allocation, statutory accounting, capitalisation policies (Transmission & Distribution)*, 8 May 2013, p. 4.

- the estimated annual fixed and variable costs.

In addition, we will require NSPs to provide relevant asset management plans and any business cases supporting key investment decisions.

Data on vehicle classes should be reported separately for two distinct categories: vehicles used predominantly for work on the network (network vehicles); and vehicles used predominantly for other purposes (non-network vehicles).

Collecting cost and usage information by vehicle class involve minimal changes and should impose limited burden on NSPs. The benefits of obtaining this information will be to better assess the efficiency of expenditure via trend analysis and benchmarking of costs across NSPs. Further, vehicle use information may allow us to better understand network costs associated with travel time, different NSP choices with respect to network operations, and assessment of potential step changes.

We are likely to consider the following elements when assessing forecast expenditure for each vehicle class:

- vehicle numbers and use—that is, does the NSP appear to have an efficient number of vehicles and use them efficiently?
- vehicle unit costs, both in relation to capital costs (return on capital plus economic depreciation) and operating costs (operating and maintenance).

NSPs commented that they collected usage data based on hours of vehicle usage as opposed to distance travelled as labour (time) costs are the key costs associated with vehicle usage. NSPs also noted that there are a range of reasons benchmark expenditure could vary across networks (e.g. due to different network design and depot locations, or due to different levels of outsourcing of contracts). It was also noted that lower utilisation may reflect a desire to have more rapid and effective emergency response.⁵¹⁸

We consider that where NSPs record vehicle usage by hours, they may report this along with data on kilometres travelled. However, we consider kilometres travelled should be systematically recorded by all NSPs (for maintenance and other reasons) and reporting this should not be a material burden for any NSP. We accept that a range of NSP specific factors will drive efficient network costs and will examine forecast expenditure taking this into account.

Assessment of non-network building and property capex

We propose to define property capex as non-network capex directly attributable to the replacement, installation and maintenance of non-operational buildings, fittings and fixtures. NSPs will be required to report non-network property expenditure by recurrent and non-recurrent expenditure.

We propose to assess recurrent expenditure primarily through trend analysis, and we may consider asset management plans, business cases and benchmark costs in assessing the efficiency of base expenditure. For non-recurrent expenditure, we are likely to assess business cases and we may conduct technical reviews of both recurrent and non-recurrent expenditure.

⁵¹⁸ AER, 'Meeting summary - Overheads, cost allocation, statutory accounting, and capitalisation policies', *Workshop 16: Category analysis work-stream - Overheads, cost allocation, statutory accounting, capitalisation policies (Transmission & Distribution)*, 8 May 2013, p. 6.

As in prior decisions, we propose to focus on large non-recurrent expenditures and the economic justifications and business cases that underpin them. NSPs are also expected to improve their economic justifications of material non-recurrent expenditure so we can better assess them against the NER requirements.

Assessment of non-network other capex

We propose to define non-network other capex as capex associated with the replacement, installation and maintenance of non-network assets, excluding motor vehicle assets, building and property assets and IT and communications assets. We expect this expenditure category will include mobile plant and equipment, tools and other miscellaneous non-network capex. We propose to assess the category primarily via trend analysis.

We are not suggesting material changes to the current assessment approach, other than expecting NSPs to provide clear economic justification of any material forecast expenditure, identification of cost drivers and departures from historic trends. This may involve providing breakdowns of expenditure into NSP specific subcategories.

Assessment of SCADA and network control capex

We propose to define SCADA and network control capex as capex associated with the replacement, installation and maintenance of SCADA and network control hardware, software and associated IT systems. However, NSPs should report common costs shared with IT and communications in the IT and communications category. This approach acknowledges the overlap between SCADA and network control, and IT and communications.

We propose to separate recurrent and non-recurrent expenditure to improve our assessment of recurrent expenditure via trend analysis. We propose to assess recurrent expenditure primarily through trend analysis. To assess the efficiency of base expenditure, we may consider asset management plans, business cases and benchmark costs. For material non-recurrent expenditure, we are likely to assess the NSPs' business cases.

We also propose NSPs improve their economic justification of both recurrent and non-recurrent expenditure so we can better assess expenditure forecasts.

B.6 Maintenance and emergency response opex forecast assessment

This section sets out our approach to assessing the maintenance and emergency response component of a NSP's opex forecast. Maintenance and emergency response include all works to address the deterioration of an asset, including when those works may be driven by reliability deterioration or an assessment of increasing risk. These expenditure categories are important because they can represent up to 55 per cent of opex for electricity NSPs.

Expenditure driven by deteriorating asset condition could include expenditure on both emergency and non-emergency rectification work, which can have significant cost differences. Non-emergency expenditure can be distinguished between replacements (capex) and other maintenance activities (opex)—a distinction that reflects the NSPs' repair-or-replace decisions. Non-emergency maintenance activities can also be distinguished between routine and non-routine activities. The timing of these activities depends on asset condition and decisions on when to replace the asset, which may vary over time and across NSPs. Further, NSPs' maintenance and emergency response activities and expenditure will differ depending on the asset to be inspected, repaired or replaced. The asset life may differ, for example, which would affect asset deterioration issues and repair-replace trade-offs.

Many NSPs currently report on routine maintenance activities that include asset inspection and vegetation management. For future assessments we propose to separate vegetation management from other routine maintenance activities.

B.6.1 Proposed approach

Our consideration of maintenance and emergency response expenditure is in the context of our overall opex assessment approach, specifically our assessment of efficient base year expenditures. To assess the efficient base year cost, we will use a variety of techniques, including analysis of individual opex categories. Our methods of reviewing maintenance and emergency response categories will include:

- trend analysis
- benchmarking of unit costs and workloads
- engineering review
- review of systems and governance frameworks.

We will consider inspections and periodic maintenance (routine expenditure) separate to reactive and condition based maintenance (non-routine and emergency expenditure).

We intend to review base year maintenance and emergency response expenditures on a more disaggregated basis in future expenditure assessments. With disaggregated analysis, we can identify factors that cause expenditure to change over time, ensure expenditure consistency across NSPs over time, and identify uncontrollable factors that influence expenditure and differ across NSPs.

We will require NSPs to disaggregate expenditures and activity volumes according to:

- asset type (poles, overhead conductors, distribution transformers, substation equipment)
- voltage
- region/location (urban, rural) (distribution only).

With the disaggregated data, we will conduct benchmarking and trend analysis of NSPs on unit rates or average costs (for example, the average inspection cost per pole, or the average unit cost of routine maintenance of an asset type over the regulatory period). We will link this analysis to supporting information (such as asset condition, supply outage information, fault types etc.) that we will require from the NSPs.

If we find any significant departure from the trend and/or benchmark, we will subject it to further detailed review when setting efficient expenditure allowances in our regulatory determinations. We will also factor the results of this analysis into our annual benchmarking reports.

We decided not to develop a deterministic routine maintenance model as we initially raised in our issues paper. Submissions from most stakeholders indicated such a model may not provide a robust forecast because a range of uncontrollable factors—such as asset age, operating environment and NSP structures—could reduce the comparability of routine maintenance expenditure and unit costs.

Summary of expected data requirements

As noted in chapter 6 on the implementation issues, we will consult with stakeholders to determine the data requirements and definitions that give effect to our proposed approach to assessing maintenance and emergency works expenditure. Table B.15 and Table B.16 summarise our general data requirements of DNSPs and TNSPs respectively.

Table B.15 Data requirements of DNSPs—maintenance and emergency response opex

Major category	Subcategory	Driver/trend/unit rate metrics	Other qualitative evidence
Routine maintenance	By asset type	Inspection/maintenance cycle	Risk profile by asset type
	By voltage	Age and condition of assets	Any new safety and compliance requirements
	By region	Network growth	Capital works programs
Non-routine maintenance	By asset type	Number of assets in the category	Risk profile by asset type
	By voltage	Age and condition of assets	Any new safety and compliance requirements
	By region	Network growth	Capital works programs
Emergency response	By asset type	Number of assets in the category	Descriptions of causes—weather events, wildlife interference, vegetation interference, traffic accidents, vandalism—that necessitated emergency response
	By voltage		
	By region		

Table B.16 Data requirements of TNSPs—maintenance opex

Major category	Subcategory	Driver/trend/unit rate metrics	Other qualitative evidence
Field maintenance	By asset type	Inspection/ maintenance cycle	Risk profile by asset type
	By voltage	Age and condition of assets	Any new safety and compliance requirements
	By region	Network growth	Capital works programs
Operational refurbishment	By asset type	Number of assets in the category	Risk profile by asset type
	By voltage	Age and condition of assets	Any new safety and compliance requirements
	By region	Network growth	Capital works programs
Other	By asset type	Number of assets in the category	
	By voltage		

For DNSPs, we will require maintenance and emergency response opex to be divided into:

- routine maintenance—activities predominantly directed at discovering information on asset condition, and often undertaken at intervals that can be predicted
- non-routine maintenance—activities predominantly directed at managing asset condition. The timing of these activities depends on asset condition and decisions on when to replace the asset, which may vary over time and across DNSPs.
- emergency response—activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are primarily due to plant failure caused by extreme weather events, vandalism, traffic accidents or other physical interference by non-related entities.

For TNSPs, where emergency response expenditure is immaterial, we will require maintenance opex to be divided into:

- field maintenance – activities predominantly directed at discovering information on asset condition, and often undertaken at intervals that can be predicted
- operational refurbishment—activities predominantly directed at managing asset condition. The timing of these activities depends on asset condition and decisions on when to replace the asset, which may vary over time and across TNSPs.
- other maintenance.

The above categories are intended to capture direct expenditures only, not overheads (corporate or network/direct overheads).

We will require NSPs to break down each expenditure group by:

- asset type
- voltage
- region/feeder classification (distribution only)
- fault type (for emergency response only).

The asset types and voltage are the same as those in the repex model that we will use to assess NSPs' replacement expenditure forecasts (see section B.3.1). Regional data on DNSP expenditure will reflect cost differences arising from network density.

We will also require standardised data on the quantitative drivers of expenditure. We will combine and otherwise examine these data against expenditures to examine any trends or significant differences in per unit costs across the NSPs. The required data include:

- routine maintenance interval (half yearly, five yearly etc.)
- the age profile of assets (per asset type)
- network growth (measured by the number of assets in each category, as well as other metrics, including the value of the asset base).

Further, we will require NSPs to provide other, non-standardised evidence to support their expenditures in each category, including:

- methods used to determine forecasts, including their key assumptions and qualitative justifications
- cost–benefit analyses of asset maintenance programs and plans, including the forecast impacts on reliability outcomes (for example, SAIDI⁵¹⁹)
- their whole-of-life asset maintenance strategies (including replacement decisions)
- risk and condition information by asset type. Many NSPs use a risk management approach to asset renewal/refurbishment, inspection and maintenance.
- the impact of changed or new regulatory/legislative requirements
- programs of capital works or replacement capex.

Emergency response expenditure is relatively unpredictable and not immediately amenable to trend or benchmarking assessment. Hence to improve our understanding of how NSPs forecast these costs and how they may arise across different NSP operating environments, we will request NSPs classify their expenditure against the following drivers:

- asset failure as a result of degradation or fault of the asset, including overhead and underground assets
- vegetation, when the primary cause of an outage was vegetation related (including trees, shrubs, bark, creepers etc.). This driver can be further divided into:
 - non-storm vegetation—that is, not associated with storm or high wind activity. It typically represents vegetation that has grown up within clearance requirements.
 - storm vegetation—that is, associated with storm or high wind activity. It typically includes outages caused by wind borne tree limbs or bark from outside the standard clearance requirements. It also includes trees and overhanging vegetation from outside the standard clearance requirements.
- weather, including flooding, high winds, lightning and insulator pollution (but excluding vegetation related outages)
- third parties, including vehicle impact with assets (such as with high loads), vandalism, sabotage, theft and single premises outages when the failure originated from the consumer’s assets
- overloads—that is, asset failure or protection operation caused by excessive, unforeseen or unaddressed energy demand
- switching and protection error, including incorrect protection settings and inadvertent trips caused by authorised persons
- unknown causes of outages

⁵¹⁹ System average interruption duration index

- other—that is, inter-network switching or connection errors, transmission failure, load shedding, emergency shutdowns at the direction of police, fire, ambulance or other related bodies.

B.6.2 Reasons for the proposed approach

Need for disaggregated expenditure data

By better understanding the expenditure drivers, we intend to significantly improve our ability to examine and determine efficient (base year) expenditures for these opex categories through benchmarking and trend analysis.

For routine maintenance activities in particular, we expect the cost of performing maintenance on particular asset types, and the number of times that maintenance is performed, to be relatively comparable over time and across the NSPs. Non-routine and emergency response opex will be relatively less easy to examine using trend analysis. However, we expect our comparisons of these expenditures against other information (including outages, asset age and condition, as well as the size of the network) will help us better understand NSPs' actual and forecast expenditures.

These comparisons will identify material differences between a NSP's historical costs and workloads, and with those of other NSPs, so we can better scrutinise specific expenditures. Further, in combination with other techniques, they will inform us about the relative efficiency of the NSPs' expenditure and the impact of uncontrollable factors.

We consider the additional cost of NSPs providing this information will be outweighed by the benefits of our improved assessment, to the benefit of NSPs and consumers. The NSPs currently report expenditures in similar aggregated categories, and they should be able to identify costs according to specific assets from their existing reporting systems (despite some burden in aligning to new, standardised asset categories). Information on outage causes for us to examine emergency response expenditure may be difficult for some NSPs to provide⁵²⁰, but we already request this information in several jurisdictions.

Asset categories

We will require a breakdown of expenditure by asset type, as per the asset groupings in our repex model. The asset categories reflect material differences in work processes involved in building, repairing or replacing assets. They also reflect differences in costs, including inspection, repair and maintenance costs. These categories will also help our analysis of the NSPs' repair-or-replace decisions and opex/capex trade-off decisions.

Benchmarking and NSP-specific factors

During workshop discussions we emphasised benchmarking is one method among many that we will use to test NSPs' capex and opex forecasts. In particular, we will use benchmarking to focus more detailed assessment techniques. Benchmarking requires standardisation of cost reporting across NSPs, as well as the identification of material drivers or activity volume measures. Common themes raised during these discussions were the need for very clear definitions and the need to account for specific NSP characteristics.

⁵²⁰ AER, 'Meeting summary - Operating & maintenance expenditure', *Workshop 11: Category analysis work-stream - Opex (Transmission & Distribution)*, 11 April 2013, p. 4.

We consider the particular driver measures in Table B.15 and Table B.16 are appropriate because they are the primary quantitative variables that could explain the changes in maintenance and emergency works expenditure. We have also identified a need to collect qualitative data because this could further explain changes in expenditure—for example, a risk assessment of the failure of wooden poles might lead to shorter inspection cycles and higher inspection costs per period.

In workshops, we raised the prospect of customer density affecting various expenditure items. Density affects DNSPs differently, given (in some cases, considerable) differences in the location and characteristics of load across the DNSPs' network areas. In some jurisdictions, distribution feeders have been categorised against the following regional categories in past reporting arrangements, in an effort to capture customer density:

- CBD
- urban
- rural—long
- rural—short.

Differences in customer density are likely to lead to significant cost differences in maintenance expenditure, so we have to consider them. We will collect the feeder type data to normalise or adjust expenditures for density and regional differences. We recognise such classifications are an imperfect measure of issues with density, and that density can affect costs in different ways. We are also open to considering how to better measure these cost impacts.

More generally, if NSPs wish for us to consider uncontrollable factors when examining benchmarking and trend data, such factors must be:

- quantified, in terms of their impact on expenditures
- supported by evidence, with the onus on NSPs to demonstrate the differences exist (including how they might materially impact on discrete parts of their networks)
- capable of robust measurement over time, and quantifiable by an independent source.

Some example factors that are not captured in our standardised analysis would include:

- the impact of jurisdictional legislation and standards
- asset condition and risk
- climate, weather and other geography-specific factors.

Expenditure categories

During consultation, stakeholders did not raise any concerns about our categorisation of DNSP opex into routine maintenance, non-routine maintenance and emergency response. They were not concerned that we subcategorised expenditure into asset types, because some NSPs already do so. However, they offered the following comments on maintenance expenditure:

- DNSPs asked us to clarify the definition of non-routine maintenance. They also noted a task can involve both routine and non-routine maintenance, but cost reporting may not be delineated.

- NSPs noted inspection cycles for equipment vary (in number of years), so it makes more sense to assess performance and expenditure over the full cycle, which could be longer than the regulatory year or control period.
- NSPs wanted to clarify the definitions of a fault and an asset failure. Further, because these are output measures, we should consider what the relevant service measures are.
- TNSPs asked us to clarify the difference between corrective maintenance and emergency response, adding that emergency response is a minor cost for transmission, compared with corrective maintenance.⁵²¹

On emergency response, stakeholders made the following comments:

- NSPs do not currently collect measures of severity (by duration or number of customers affected).
- NSPs have found it hard to collect accurate, consistent data on causes of faults (animals, weather or asset condition).
- Voltage levels do not appear to drive costs, although they do drive priorities. Costs are driven more by asset type than voltage.
- Data on faults due to asset failure by asset type may be difficult to obtain.
- In terms of normalisation factors, NSPs commented some measures of outage severity may offset each other—for example, the installation of more reclosers in rural areas results in worsening MAIFI⁵²² but improving SAIFI^{523 524}.

We endeavoured to address the above comments in the draft Guidelines. Many of these issues relate to detailed definitions, on which we will consult when we develop regulatory information instruments. To the extent that the definitions affect our proposed assessment approach, we will also encourage further submissions from stakeholders in response to the draft Guidelines.

Transitional and implementation issues

During consultation, stakeholders questioned the ability of NSPs to provide disaggregated data on repairs and maintenance costs when they outsource activities. The NSPs might contract out their maintenance works, for example, on a medium to long term basis. Contracts might also be based on a lump sum payment, unit rates of work performed, or a combination of the two. Further, a contract might cover the total NSP service area or be broken into separate contracts to facilitate competition and comparison.

The accuracy of the data that we request will be affected by the persistence of existing contracts under which NSPs are not provided this information. In this case, we will require NSPs to use best endeavours (with an assurance report) to comply with our information requests—for example, to provide details on how information was estimated. Once existing contracts expire, we expect new contracts will enable NSPs to collect accurate data from their service providers.

⁵²¹ AER, 'Meeting summary - Operating & maintenance expenditure', *Workshop 11: Category analysis work-stream - Opex (Transmission & Distribution)*, 11 April 2013, p. 4.

⁵²² Momentary average interruption frequency index.

⁵²³ System average interruption frequency index.

⁵²⁴ AER, 'Meeting summary - Operating & maintenance expenditure', *Workshop 11: Category analysis work-stream - Opex (Transmission & Distribution)*, 11 April 2013, p. 3.

B.7 Vegetation management expenditure forecast assessment

This section sets out our approach to assessing the vegetation management component of a NSP's opex forecast. Vegetation management is the process of keeping trees and other vegetation clear of electricity lines to reduce related outages and the potential for fire starts. Vegetation management also includes clearing easements and access tracks associated with electrical assets. It is an important expenditure category because it can represent up to one-third of operating expenditures for many NSPs. It is also unique because most NSPs outsource their vegetation management work to contractors.

We and our consultants have primarily relied on the revealed cost approach when setting our own vegetation management opex forecasts in past determinations. We:

- reviewed NSP vegetation management programs and historical expenditures
- trended forward vegetation management costs from a base year, accounting for the expected growth in relevant drivers
- assessed NSPs' estimated volumes and unit costs in response to step changes in expenditure.

As well as the revealed cost approach, we have also on occasion:

- compared vegetation management workloads across distribution network service providers (DNSPs).⁵²⁵
- identified drivers and reviewed strategy, legislation and contracts.⁵²⁶

We intend to review vegetation management on a more disaggregated basis in our upcoming expenditure assessments. We also intend to inform our vegetation management review with benchmarking and trend analysis.

B.7.1 Proposed approach

To assess base year expenditures, including as part of annual benchmarking reports, we will assess the efficiency of a NSP's vegetation management expenditures. This will occur with both overall forecasts for vegetation management as well as for component expenditure items. Our process in assessing these forecasts is likely to occur in the following manner:

- We will examine and assess the disaggregated data provided to us by the NSP and assess the breakup of costs and outcomes. This would include but is not limited to:
 - trend assessment—we would examine forecast costs of vegetation management activities by trending forward actual expenditure. This would be applied to activities such as tree cutting, inspections and easement clearing.
 - category benchmarking—we would compare unit costs and drivers for specific vegetation management activities (for example, cost per tree cutting, easement clearing) across NSPs. We would evaluate a NSP's performance with comparable NSPs. We will conduct further

⁵²⁵ For example see: Nuttall Consulting, *Report – principle technical advisor: Aurora distribution revenue review: Operating expenditure base-line: A report to the AER*, November 2011, p. 43.

⁵²⁶ For example see: Nuttall Consulting, *Report – principle technical advisor: Aurora distribution revenue review: Operating expenditure base-line: A report to the AER*, November 2011, pp. 43–44.

assessment when our techniques indicate a significant difference in the costs or effectiveness of a NSP's vegetation management program.

- assessing data on vegetation caused outages and bushfire starts to determine the effectiveness of NSPs' vegetation management programs.
- using information collected on normalisation factors such as tree growth rates and legislative requirements for qualitative assessment. If we identify differences in unit costs across NSPs, we will consider if the normalisation factors can account for the difference.
- We will consider technical reviews, governance reviews and the NSP's forecast methods.

Summary of expected data requirements

We require NSPs to provide us with disaggregated data of their vegetation management activities, outcomes and drivers. Table B.17 and Table B.18 summarise these data requirements for distribution and transmission NSPs respectively.

The 'major category' column outlines the vegetation management activities for which we intend to collect expenditure data. The 'sub-category' column shows how we propose to disaggregate the expenditures for major categories. 'Quantitative measures' refer to the various drivers and outputs for which we intend to collect standardised data that will be used to explain expenditures. 'Qualitative evidence' outlines the additional, non-standardised information we will consider in our analysis of expenditures.

Table B.17 Vegetation management data requirements—distribution

Major category	Sub category	Quantitative measures	Qualitative evidence
Tree trimming, ground clearance	Urban/ rural; high/low voltage, zone	Km of overhead line in management area, number of trees, clearance cycles,	Tree growth rates, tree species, rainfall, sunshine, fire starts, outages due to veg contact, legislative requirements
Inspection, audit	Urban/ rural; zone	Km of overhead line in management area	Legislative requirements
Easement clearance	Rural; zone	Km of easement	Outages due to vegetation contact, fire starts, legislative requirements,
Access track clearance	Zone	Km of access track	Legislative requirements

Table B.18 Vegetation management data requirements—transmission

Major category	Sub category	Quantitative measures	Qualitative evidence
Easement clearance	Forest, grassland, etc.; zone	Km of overhead line in management area, number of trees, clearance cycles,	Tree growth rates, tree species, rainfall, sunshine, fire starts, outages due to veg contact, legislative requirements
Access track clearance	Forest, grassland, etc.; zone	Km of access track	Legislative requirements
Inspection, audit	Forest, grassland, etc.; zone	Km of overhead line in management area	Legislative requirements

We propose to disaggregate vegetation management expenditure for DNSPs and TNSPs differently. While there are many similarities in the outputs and drivers of the two network types, there are differences in network characteristics. This section discusses vegetation management zones, expenditure classifications and other data requirements in further detail. It also explains differences in our assessment of DNSP and TNSP forecasts.

Geographic splits and zones

Feeder classification (CBD, urban and rural) is a commonly used geographical disaggregation for DNSPs that we request for vegetation management expenditure. Additionally, disaggregating by zone accounts for differences in clearance margins surrounding lines carrying different maximum voltages. We would expect the unit costs for tree trimming or ground clearance to differ depending on geography, clearance margins, regulations and other factors.

By contrast, disaggregating by CBD/urban/rural is not appropriate for transmission. An alternative is to disaggregate based on the geographical characteristics present across access tracks or within an easement area. There are issues in defining areas based on geographical characteristics. For our purposes, we consider geographical characteristics to be different from vegetation management zones. Geographical characteristics will be considered within each zone set by the TNSP, with the characteristics expected to indicate differences in TNSPs unit costs for easement clearance.

Businesses would set the vegetation management zones. To the extent that they already do so, NSPs should continue to reflect reported data and operating environments across zones. This would be based on the recognised drivers (regulations, tree growth rates, and tree cutting cycles). We expect this to be only relevant for larger NSPs (by area) and expect around 10 to 20 zones that identify differences across their network, with fewer zones for smaller networks.

Within each nominated zone the NSP would provide information on:

- the regulations it must comply with when performing vegetation management activities within that zone
- tree growth rates in that zone
- tree cutting cycles in that zone

- the total cost of tree trimming within that zone
- the total route-length kilometre of line requiring vegetation management within that zone
- the dimensions of easement within that zone
- any NSP imposed standards for vegetation management activities within that zone.

Tree trimming expenditure

We will request data from DNSPs on the number of trees trimmed in each vegetation management zone, and ground clearance⁵²⁷ cost per kilometre (of line exposed to vegetation) in each zone, disaggregated in proximity to:

- sub-transmission lines
- lines from high voltage (CBD/urban/short rural/long rural) feeders
- lines from low voltage (CBD/urban/short rural/long rural) feeders.

Expenditure on the number of trees trimmed will be examined with the overall cost of tree trimming by zone to determine the cost per tree cut.

For TNSPs we will also request tree trimming data as they may engage in tree trimming, particularly where trees may grow within the required minimum easement width. We will request this with other easement clearance data.

Easement clearance expenditure

For DNSPs we request data on the cost of easement clearance per kilometre within each zone. These costs may be material for some NSPs, particularly those that operate in rural areas.

For TNSPs we will request data on easement clearance (cost per route-length kilometre of easements requiring vegetation management), by vegetation management zone, disaggregated into:

- forested area
- grassland/ farmland
- cities and townships
- other

We will be benchmarking unit costs across TNSPs and considering the cost of easement clearance over time in our trend analysis.

Audits and inspections expenditure

For DNSPs we will request data on the audit and inspection cost per kilometre within each zone, from CBD/urban/short rural/long rural feeders.

⁵²⁷ We define ground clearance costs as costs involved in the trimming of low-lying vegetation including grass, shrubs, tree sprouts etc.

For TNSPs we will request data on the audit and inspection cost per route-length kilometre, by vegetation management zone, disaggregated by:

- forested area
- grassland/ farmland
- cities and townships
- other.

We aim to keep inspection/auditing costs separate from the cost of tree trimming. Recording these costs on a per kilometre basis is intended to account for tree density. Tree density needs to be considered because more trees per kilometre will directly increase the inspection cost per kilometre. Recording by zone is for consistency with collection of tree trimming data, and to simplify comparisons when regulations may affect the cost of inspections or audits, for example, bushfire regulations.

Access track clearance expenditure

For DNSPs we will request data on the cost of access track clearance per kilometre, by vegetation management zone. Access track clearance costs may be material for some DNSPs, particularly ones that operate in rural areas; therefore we consider it necessary to collect data on this activity.

Access track clearance costs are also significant for TNSPs; therefore we consider it important to examine the unit cost of performing this activity. We will be benchmarking unit costs across TNSPs and considering the cost of access track clearance over time in our trend analysis. The disaggregation by geographical characteristic is intended to be consistent with other input activities for TNSPs. For TNSPs, we will request data on the maintenance of access tracks (cost per route-length kilometre of access track), by vegetation management zone, disaggregated into:

- forested area
- grassland/ farmland
- cities and townships
- other.

Contractor management expenditure

Most NSPs hire contractors to perform their required vegetation management work. We consider it is necessary to record costs for contract negotiation and contractor liaison because they may be material. This is separate from the entire contract cost.

Some NSPs may engage related parties to perform their vegetation management work. We discuss assessing the efficiency of forecast expenditures of related parties in chapter 4 of the explanatory statement.

Travel costs

We may collect data on costs associated with travel, including time spent travelling and living-away-from-home costs. We propose leaving recording travelling costs as an open question. We believe these costs are significant and worth recording, but we are aware these costs may not be visible to NSPs. Living-away-from-home costs may include accommodation, meals and other sundries.

Non-expenditure data

Cutting cycles

We will request data on the frequency of the cutting cycle, by vegetation management zone because the frequency of cutting affects the cost of tree cutting over an extended period. NSPs would incur greater costs in areas cut on more frequent cycles. This must be factored into both our trend analysis and category benchmarking.

Tree growth rates

We will request data on tree growth rates within vegetation management zones, including information on:

- species, and the proportions of those species of total trees within the NSP's zone.
- climate, factoring in temperature, rainfall etc.

We will use data on tree growth rates in a qualitative manner. We will use the data to consider if growth rates can account for differences in tree cutting costs across NSPs. We will also use the data to support information provided on the cutting cycle; for example, we may expect that DNSPs would engage in more frequent tree clearing if vegetation within a particular zone grows quicker.

We recognise using tree growth rates as a normalising factor will be difficult given the issues surrounding its measurement. We discuss this in more detail below.

Regulatory/legislative requirements

We will ask NSPs to provide a list of regulations that impact the operation of their vegetation management scheme across their entire network and within vegetation management zones. This includes primary legislation and other legislation that has a material impact on costs (such as weed control legislation). A complete list of regulations that affect distribution businesses is intended to help us determine operating costs for vegetation management activities performed across the entire network, allowing us to identify differences across NSPs.

Recording a list of regulations by each specified management zone is intended to account for cost differentials within a business's network. Regulations may affect frequency of activity, for example; they may require businesses to trim the vegetation surrounding their networks at specific intervals.

Fire starts due to vegetation contact

We will request NSPs provide data on vegetation caused fire starts, disaggregated by vegetation management zone.

Unplanned, sustained outages and faults due to vegetation contact.

We will request NSPs provide vegetation caused outage data disaggregated by vegetation management zone.

We will use data on outages and fire starts to consider the effectiveness of a NSP's vegetation management scheme. The data will not be used in a deterministic manner because outages and fire starts may still occur despite NSP compliance with regulatory or statutory obligations. It will be considered as a measure of the effectiveness of a vegetation management scheme when considering any cost changes.

Outage data will also not be considered for category benchmarking because an outage may not be attributable to a specific cause; for example, a branch falling onto a line on a windy day may be attributable to either vegetation or weather. Each NSP may attribute such an outage specifically to either cause.

B.7.2 Reasons for the proposed approach

Vegetation management can make up a substantial part of a NSP's total operating expenditure. We therefore consider it cost effective to disaggregate this category to improve our ability to assess forecasts of these costs. We currently assess vegetation management expenditure at the aggregate level. We have not systematically assessed this expenditure at a disaggregated level in the past, reflecting the lack of standardised data. As a result, we do not have a thorough understanding of vegetation management costs and activities across NSPs.

We will continue to assess vegetation management expenditure as part of our overall base step trend approach to opex at the aggregate level (section 4.2). We will adjust the vegetation management expenditure forecast only if any concerns arise in our assessment of opex base year expenditures.

We consider applying trend assessment to specific vegetation management activities is useful, given their predictable and recurrent nature. Trending forward actual data on specific activities will provide us with a better understanding of the reasonableness of NSPs' forecasts.

Benchmarking costs at the activity level will indicate the relative efficiency of the NSP in conducting vegetation management works. This will be useful in addition to trend assessment because it will indicate the NSPs' historical efficiencies, and it will allow us to adjust a NSP's revenue allowance accordingly. We intend to benchmark a number of activities on a per kilometre of line basis. We consider this is an effective comparative measure because a per unit comparison—specifically, a per kilometre measure—will be simple to calculate. Such benchmarks are expected to form a solid basis for comparing like activities and various cost differences between NSPs, and hence will help us understand NSPs' individual operating environments.

The geographical disaggregation (urban/rural for DNSPs; forest, grassland, etc. for TNSPs) is expected to reflect discrete sections of NSPs' networks where costs are affected by different geographical characteristics. The urban/rural disaggregation for DNSPs is already a commonly used measure for a variety of activities. Disaggregation by forest, grassland, and other measures is expected to be the most reasonable disaggregation that can be applied for transmission networks.

If they do so already, NSPs should also classify expenditure and quantitative measures according to 'zones'. Classification by zone is intended to broadly reflect material differences in the type and growth rates of vegetation as well as legal obligations that do not affect the network uniformly. This is expected to be the case only for NSPs operating over larger geographic areas.

Tree trimming data requirements

Data on the number of trees trimmed will be examined with the overall cost of tree trimming by zone to determine the cost per tree cut. Tree trimming is a significant part of vegetation management expenditure; therefore we consider it important to examine the unit cost of performing this activity. We also consider ground clearance costs and easement clearance costs are material and should be examined on a unit cost basis.

We considered recording data on spans cleared and separating works on hazard trees. Ofgem records tree trimming/removal work by the number of spans affected, irrespective of the number of

trees per span.⁵²⁸ We consider this would not be an ideal measure in Australia given the wide discrepancy in span length across geographical areas; however we will consult with stakeholders on the benefits and issues arising from collecting data by span.

Recording the clearance of hazard trees as its own category is still an open question. Hazard trees may need to be cut by some NSPs, which will add to overall tree trimming costs. We would like to record this, but we recognise that contractors may not collect this data, it may not be relevant in all jurisdictions, and this additional information may be of little material benefit. Clearance of hazard trees may be easier to include within all tree trimming activities.

Data availability

An issue with collecting disaggregated vegetation management data is that NSPs may not actually collect a large proportion of the data themselves. Much of the data could only be obtained via contractors.

NSPs generally contract their vegetation management works on a medium to long term basis. The contracts may be based on a lump sum payment, by unit rates of work performed, or a combination of the two. The contract may cover the total NSP service area or be broken into a number of separate contracts to facilitate competition and comparison.

Collection of additional data may only occur once new contract periods begin. This could be up to three to five years from now, after which we could request a complete list of data. We collect only aggregate data on vegetation management at present.

We intend to ask NSPs for data on all vegetation management activities when they are issued with their first data request. If NSPs are unable to provide data in the short term, we will request NSPs provide an indication of when they could provide the data. We will use estimates of the relevant expenditure in the meantime.

Measurement of tree growth rates

We recognise using tree growth rates as a normalising factor will be difficult, given measurement issues. Tree growth rates vary by species, geography and climate. Trees in warmer, tropical climates are expected to grow quicker than trees in drier areas. Obtaining accurate data on tree growth rates by species and region is a challenging task. This point was raised by the ENA in its submission to the issues paper; they noted a number of highly variable factors, including tree species, climatic conditions, weather and soil type.⁵²⁹ We intend to work with stakeholders to develop a process to source and use data on growth rates.

Information on tree growth rates may include the following qualitative and quantitative information:

- approximations of percentage of tree types across network
- identification of the factors that impact on tree growth rates; these may include historical rainfall, sun exposure, temperature etc.
- correlation of changes in historical expenditure levels to a rainfall, temperature or sunshine index

⁵²⁸ Ofgem, *Strategy decisions for the RIIO-ED1 electricity price control - tools for cost assessment*, March 2013, p. 66.

⁵²⁹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, Attachment B, p. 7.

- matching of the weather stations in proximity to their vegetation management zones/ or to the path of their lines, and ask for an average of the data recorded at those stations. The Bureau of Meteorology records daily rainfall and sun exposure data collected from its numerous weather stations.⁵³⁰

An imperfect but practical measure may be to use an average zone tree growth rate as the normalisation factor. Although the degree to which trees are trimmed depends on the species and its expected growth rate, the frequency of trimming might be identical by area regardless of the species. Assuming this, the difference in the degree of vegetation removed may not significantly affect costs.

Defining zones and geographical areas

The purpose of disaggregating NSPs' vegetation management activity by a 'zone' is to identify major differences in drivers across parts of a network. Costs of vegetation management activities would be measured by zone, using information from the drivers to determine reasons for cost differences.

A number of submissions to the issues paper highlighted that many different drivers affect costs of undertaking vegetation management activities.⁵³¹ We consider that by disaggregating a NSP's network by zone, we can control for the various regulatory drivers that affect costs, such as bushfire regulations.

We propose NSPs establish their own vegetation management zones because they would have greater knowledge of the regulations that affect their network. They would be asked via a text entry area within the data template if the established zones are defined by legislation or established themselves.

For transmission geographical areas, the location of the easement or access track within forested area, grassland or other areas has a significant impact on the amount of work required to clear an easement, for example tree trimming. We have proposed to disaggregate data by forest, grassland, and cities and towns but recognise that defining these categories may be difficult. We will work with stakeholders to determine appropriate definitions.

The ruggedness of terrain is a significant factor in maintaining easements and access tracks. Costs of access may increase with more rugged terrain. However, defining 'rugged', 'hilly' or 'mountainous' terrain would be difficult. If it is defined and collected, we could assume some overlap with collection of data from forested areas, which are also likely to exhibit a significant degree of elevation change. Assuming forested terrain is also rugged or mountainous may be the easiest alternative to ease data collection.

B.8 Overheads forecast assessment

This section sets out our approach to assessing the overheads component of a NSP's opex forecast. NSPs, in addition to building, repairing and replacing network infrastructure, also incur expenditure on planning and managing how they undertake these activities. Various terms refer to this planning/managing expenditure, such as overheads, shared costs, indirect costs or fixed costs.

⁵³⁰ See <http://www.bom.gov.au/climate/data/stations/>

⁵³¹ Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, pp 6–7; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, Australian Energy Regulator, 15 March 2013, p. 16; Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, p. 12; Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 36.

We use the terms 'overheads' and 'shared costs' interchangeably to refer to planning and managing expenditure. These costs cannot be directly attributed to the provision of a particular category of services or activities, but are typically allocated across different service categories. By contrast, 'direct costs' are those costs that can be directly attributed to the provision of a particular category of services or activities

Overheads represent a significant proportion (up to about one third) of total opex. They can be further distinguished into two types—namely, 'direct' and 'indirect' overheads. We use the term 'direct overheads' to refer to network overhead costs, and the term 'indirect overheads' to refer to corporate or other overhead costs.

Network or direct overhead costs typically include system planning and design, system operations, procurement, logistics and stores, capital governance, works management and customer service.

Corporate or indirect overhead costs typically include those for chief executive officer, legal and secretariat, human resources and finance activities.

B.8.1 Proposed approach

Our consideration of the NSPs' forecast overheads expenditure is in the context of our overall opex assessment approach, specifically our assessment of efficient base year expenditure (section 4.2). To assess the efficient base year cost, we will use a variety of techniques, including analysis of individual opex categories.

We will examine overheads—aggregated, unallocated and before capitalisation—separately and benchmark these against those of both other NSPs and comparable firms in other (non-energy) industries. Such benchmarking will need to control for scale variables, such as staff numbers in terms of corporate overheads, and network size or value in terms of network overheads. We also propose to examine particular overheads categories by collecting information on likely drivers and other benchmarking metrics to identify trends and material differences in costs incurred by the NSPs. For many categories, we expect some costs to contain fixed and variable proportions.

If we find any significant departure from the trend and/or benchmark, we will subject it to further detailed review when setting efficient (base year) expenditure allowances in our regulatory determinations. We will also factor the results of this analysis into our annual benchmarking reports.

Summary of expected data requirements

For network overheads, we will continue to require NSPs to report against existing subcategories. But we will require disaggregation of the currently reported 'network operating costs', so we can undertake further detailed review if we assess the total cost forecast is inefficient.

Similarly, for corporate overheads, we will implement standardised expenditure categories that largely mirror those material expenditures already reported to us by most NSPs.

We intend to assess both categories of overhead expenditure in the aggregate (unallocated total and before capitalisation) to minimise the effects of different cost categorisations, cost allocation methods and capitalisation policies used by the NSPs.

Example drivers/normalisation metrics include those related to the size of the network, as well as measures to capture explanatory variables and their proxies (including direct expenditures and employee numbers). We will also request NSPs to explain how different approaches to capitalisation,

cost allocation and jurisdictional factors (for example, service classification) affect their reporting of overheads.

Table B.19 and Table B.20 outline our expected data requirements.

Table B.19 Data requirements of NSPs—network/direct overheads

Expenditure/activity categories	Example drivers/metrics	Other information	supporting
Network operating			
▪ Network management			
▪ Network control	Network size	Cost allocation method and data	
▪ Network system operations	Network value (undepreciated RAB, or current replacement cost)	Capitalisation policy, and any changes during the regulatory year	
▪ Other			
Meter reading	Customer numbers		Jurisdictional voltage differences (if material)
Customer services	Total direct costs		
Billing and revenue collection			
Other			

Table B.20 Data requirements of NSPs—corporate/indirect overheads

Expenditure/activity categories	Example drivers/metrics	Other information	supporting
Advertising, marketing and promotions			
Other operating/support costs			
Superannuation			
Chief executive officer			Service classifications
Legal and secretariat		Revenue	Cost allocation method
Human resources	Number of employees		Related party margins
Finance	Customer numbers		Outsourcing arrangements—IT, communications, vehicles
Regulatory	Total direct costs		Lease-or-buy information for major assets—IT, communications, vehicles
Capital governance			
IT and communications*			
Procurement/logistics*			
Training and occupational health and safety*			
Motor vehicles*			

* These four items—IT and communications, procurement, training, and motor vehicles—should exclude that part of expenditure attributed to or allocated to field or network related activity (which would form part of network overheads).

Data specifications affecting direct cost categories - input and allocated costs

We are proposing to require NSPs to report costs for direct cost categories (e.g. repex, maintenance etc.) into labour, materials, contract and overheads. While this does not necessarily relate to the

reporting of overheads, it is discussed here in the context of overheads allocation and related capitalisation issues.

Reporting of input costs as well as any allocated costs should be in accordance with the NSP's capitalisation policies and cost allocation methods. Allocations should be reconcilable across direct cost categories as well as across business units where a NSP is involved in providing unregulated services. We will be seeking information to have visibility of these reconciliations, for example, to statutory accounts.

This information will be used to examine the materiality of differences in NSPs' corporate structures, policies and major contractual arrangements. Where NSPs are unable to provide disaggregated information on these input and allocated costs, they will be required to make reasonable and transparent estimations.

B.8.2 Reasons for the proposed approach

We intend to significantly improve our ability to examine and determine efficient base year overhead expenditures through benchmarking and trend analysis, with improved understanding of expenditure drivers. We will continue to carefully examine shared costs, which form up to one third of total expenditure and materially affect the opex and capex forecasts.

By assessing network overhead and corporate overhead separately, we can compare these expenditures over time and across NSPs. Comparisons of these expenditures against supporting information—including cost allocation methods, capitalisation policies, service classifications and any outsourcing arrangements—will help us better understand NSPs' actual and forecast expenditures, and to scrutinise specific expenditures. Further, these comparisons will help us better understand the relative efficiency of a NSP's expenditure and the impact of uncontrollable factors.

In addition to improving our understanding of overhead costs, the separate identification of these costs from direct expenditure categories (such as maintenance and augmentation capex) will better enable us to robustly compare those direct expenditure categories across NSPs. That is, the impact of NSPs' overheads allocation (and capitalisation) policies may be significant, and we need to control for it when comparing direct costs.

We considered and the benefits of our general approach and the data required will outweigh the associated cost. The separate reporting of overheads costs will result in minimal burden on the NSPs. NSPs currently report expenditures similar to the categories outlined above, and they should be able to identify costs from their existing reporting systems to align with any new, standardised overhead categories. The benefits of our approach are likely to be substantial because we have not systematically assessed overhead costs in such a way before, and the separation of overheads from other direct expenditures will be necessary to effectively benchmark those direct expenditures.

Impact of cost allocation methods

The NSPs' different approaches to cost allocation are a source of incomparability in benchmarks. Some NSPs fully allocate their overhead costs to activities or drivers, reporting items such as head office costs against categories such as asset augmentation and replacement. But other NSPs allocate costs by a different method.

During consultation, stakeholders indicated majority support for separate reporting of overheads and, due to the NSPs' different cost allocation methods, for assessing overheads at an aggregate level before allocation. Stakeholders considered the inclusion of overheads in expenditure categories, and

NSPs' different methods to allocate overheads, adversely impact the AER's ability to assess whether costs are efficient through benchmarking techniques.⁵³²

Stakeholders also noted potential issues in assessing overheads at an aggregate level and in isolation. One NSP noted it provides more unregulated activities (services not classified as standard control services) compared with other NSPs. If overheads were assessed in the aggregate, then the NSP's results would be distorted against those of other NSPs without similar levels of unregulated activities.⁵³³

Stakeholders also stated the corporate structures of NSPs influence how they classify costs as direct or indirect costs. The NSPs that are part of a larger corporate group, with a number of different functions provided at a group level, are likely to classify these functions as overheads instead of direct costs. A smaller NSP might classify the same functions as direct costs. The presence and degree of outsourcing of certain services (such as IT, communications and vehicles) also complicate the assessment of overhead expenditures.⁵³⁴

Reflecting on views expressed in consultation, we expect NSPs will maintain different cost allocation approaches in accordance with the NER. Prescribing a standard cost allocation policy or method across all NSPs is unlikely to make sense. Our approach to accounting for different cost allocation methods is to benchmark capex and opex direct costs only, and to separately benchmark unallocated overhead costs.

We still need to resolve issues around the potential allocation of costs (particularly labour) at the direct cost level—for example, the use of work crews who completed multiple projects but whose time was not directly recorded against each project. This problem is similar for capitalisation policies (see below).

Our approach to dealing with this issue is to obtain sufficient detail from NSPs on how they allocate overhead costs. We will require NSPs to provide enough detail regarding these allocations to allow us to assess expenditure consistently across NSPs. Our proposed solution is to require NSPs to disaggregate cost categories into direct labour, direct materials, contracts⁵³⁵ and allocated overheads. This disaggregation will help our forecast assessment in several ways:

- we will better understand expenditure drivers, because labour and materials each have different real cost escalators and productivity growth
- we will better understand the allocation of overheads—that is, how they are allocated to direct cost categories, and how the overheads total reconciles with the sum of all allocated overheads

⁵³² Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 22; Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, 8 March 2013, Attachment B, p. 7; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 17; Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013, pp. 12-13; Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, p. 37; United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator*, 19 March 2013, p. 15.

⁵³³ Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, p. 17.

⁵³⁴ AER, 'Meeting summary - Overheads, cost allocation, statutory accounting, and capitalisation policies', *Workshop 16: Category analysis work-stream - Overheads, cost allocation, statutory accounting, capitalisation policies (Transmission & Distribution)*, 8 May 2013, p. 2.

⁵³⁵ For major contracts, we require the NSP to disaggregate the contract cost into labour, materials and overhead.

- we will better understand the capitalisation of opex—that is, how some overhead is allocated to capex direct cost categories, thus becoming part of the RAB.

We recognise this creates additional reporting burden for NSPs where we are already proposing to disaggregate direct cost categories for the purpose of improved trend and benchmarking analysis. However, we anticipate NSPs already retain this data and, in cases where they do need to be approximated, NSPs will have robust and transparent methods of doing so.

Capitalisation policies

A NSP's capitalisation policy is its policy of reporting certain costs as capex or opex. As with cost allocation policies, these decisions of a NSP to classify costs in a certain way potentially detract from benchmarking comparisons. This matter is different from our consideration of whether a NSP incurs cost in addressing a particular need (for example, deterioration in asset condition) through a capital versus an expensed solution. Such capex/opex trade-offs are important and addressed in section 4.1.2.

During consultation, NSPs questioned our intent on examining capitalisation policies, particularly whether it is related to ex post reviews of the RAB or to our benchmarking. They noted limited instances of changes to capitalisation policies mid-period that would warrant a reconsideration of RAB values. Further, the issue of capitalisation policies in the context of the ex-post review process is addressed by our separate Draft Capital Expenditure Incentives Guidelines.

Visibility of how capitalisation policies affect reported capex would be useful if they changed mid-period (in reflection of RAB issues). However, the more material issue for benchmarking is how policies differ across NSPs at any time, and the extent to which the differences affect robust comparisons of direct costs. Our proposed solution is similar to our approach to assessing cost allocation policies. That is, we will require full visibility of the impact of different capitalisation policies at the detailed level across all cost categories. For capex and opex direct costs, we will require the NSPs to disaggregate direct costs into labour, materials and allocated overheads.

Finally, we note the current TNSP information guidelines require a recasting of historical expenditure data in regulatory proposals if capitalisation policies are changed. We will give effect to this requirement for all NSPs under the new Guidelines and through regulatory information instruments. That is, if a NSP changes its capitalisation policy, then we will require it to identify how such a change affects any historical data on which we rely for category assessment (this is in addition to capex as it relates to the RAB provisions under the NER and our Draft Capital Expenditure Incentives Guidelines).

C Summary of submissions

Table C.1 Summary of submissions on our issues paper

Issue	Respondent	Comments
Question 1 Should we anticipate the application of some assessment techniques to gas service providers as part of this consultation?	Energy Networks Association	ENA: Yes. The guidelines should not formally be applied to gas service providers. However, understands that the AER envisages the outcomes of this process, particularly the principles and concepts, may be treated as a precedent for future development of gas service provider assessment techniques. (p. 7)
	SP AusNet	SP AusNet: The use of these techniques is clearly applicable to gas businesses, and from a practical perspective may be easier to apply than in electricity (for example, differentiation between deferral and permanent cost saving more straight forward to observe in gas distribution). However, concurs with the AER that the scope of the current exercise should be on producing guidelines for electricity NSPs. (p. 5)
	Public Interest Advocacy Centre	PIAC: The AER should focus on electricity but recognise some discussions will be relevant to gas, noting different drivers and expenditure categories. (p. 7)
Question 2 Do stakeholders have any preliminary comments on the development of guidelines that will be different for transmission and distribution businesses? Should consultation be separate for these businesses?	Energy Networks Association	ENA: As noted by the AER, differences exist between transmission and distribution businesses which will need to be addressed in the development of these guidelines. A separate consultation process and separate guidelines are necessary to address transmission specific issues. (p. 3)
	Ergon Energy	Ergon: Supports the development of guidelines for transmission businesses, but believes these should be developed separately from those developed for distribution businesses. The environment in which transmission businesses operate is significantly different to that of distribution businesses. (p. 7)
	SP AusNet	SP AusNet: There are important differences in the characteristics, technologies and functions of transmission and distribution that necessitate the application of different approaches in these two sectors. It is evident that the AER is aware of these differences, and recognises their implications for assessment techniques. It is important for the AER to ensure that these differences are properly recognised in the development of the Guidelines and therefore suggest that the AER consult separately on the development of the Guidelines for transmission and distribution. (p. 5)
	Aurora Energy	Aurora: Does not consider it necessary to conduct separate transmission and distribution consultations. Expects a difference in guidelines between those TNSPs that are and are not subject to NEL Part 5, Division 2, subdivision 3. (pp. 2–3)
Question 3 How should linkages between expenditure assessment, information collection and storage, cost allocation and incentive	Energy Networks Association	ENA: The annual and determination RINs involve a significant amount of work and effort to produce. Ideally, the annual benchmarking reports and new expenditure techniques can leverage off this existing work. To ensure minimal disruption to the businesses, the information could be collected incrementally over several years. (pp. 7–8)
	Ergon Energy	Ergon: Has concerns with the interaction between responding to current incentives and the AER's substitution of expenditure forecasts in the future. The current regulatory framework has been developed with incentive mechanisms as a
	SP AusNet	
	CitiPower, Powercor, SA Power	

arrangements be dealt with in the development of our overall assessment framework?	Networks (joint submission) Public Interest Advocacy Centre Aurora Energy	<p>core element, in recognition of the fact that no assessment framework can accurately determine future efficient costs with a suitable level of accuracy, or in the absence of detailed knowledge and information, such as engineering expertise and risk assessment studies. (p. 7)</p> <p>SP AusNet: The Issues Paper notes that the application of the assessment techniques envisaged by the AER will necessarily involve an extensive information collection and storage exercise. The RIN should be the vehicle for gathering data for annual benchmarking reports and the expenditure assessment techniques. (p. 7)</p> <p>CP/PC/SAPN: The AER developed its EBSS on the basis that, in assessing opex forecasts, it would place significant weight on the actual opex in the base year of the current regulatory control period (i.e. would adopt a revealed cost approach). Changing the approach to expenditure assessment would necessarily change the impact on incentives arising from the EBSS, with the result that the incentives established by the scheme may no longer be effective or appropriate, including in light of the NER requirements to provide for a fair sharing of efficiency gains and losses. The AER must have regard to the costs associated with information collection and storage in the selection of expenditure assessment techniques. The relevant NER requirements may not permit the AER to standardise cost allocation methods. Changes to cost allocation that involve significant costs to NSPs should be highlighted by the AER. (Attachment A, p. 2)</p> <p>PIAC: Note the PC's recommendation for the AER to establish a public database of benchmarking data. Questions of confidentiality become more critical but should not be a reason for not proactively addressing data availability. (p. 7)</p> <p>Aurora: Costs of preparing and maintaining information to satisfy the AER's requirements should be regarded as regulatory obligations or requirements and excluded from incentive schemes. Small incremental costs are expected in terms of data storage, however, those for IT systems to maintain backwards compatibility for 10 years are unlikely to be trivial, including for other NSPs. (p. 3)</p>
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<p>Question 4</p> <p>Have we appropriately characterised the role of benchmarking in expenditure assessments, and set an appropriate objective in expanding and formalising our approach in consultation with stakeholders?</p>	<p>ActewAGL</p> <p>CitiPower, Powercor, SA Power Networks (joint submission)</p> <p>Energy Networks Association</p> <p>Major Energy Users Inc.</p> <p>Ergon Energy</p> <p>Public Interest Advocacy Centre</p> <p>SP AusNet</p> <p>Aurora Energy</p>	<p>ActewAGL: Does not support the use of benchmarking to mechanistically set allowances, rather it is a useful tool or filter that should support rather than drive regulatory decisions. (p. 1)</p> <p>CP/PC/SAPN: The issues paper has characterised benchmarking as having a role of greater significance than possible for the next round of determinations. No current benchmarking techniques exist that, even with perfect data quality, would be able to replace the revealed cost approach and base step and trend methods for opex or bottom up assessments for capex. (Attachment A, pp. 2–3)</p> <p>ENA: No. The AER has overstated the realistic and appropriate role that benchmarking assessment can play, especially in the immediately upcoming round of reviews. No benchmarking techniques currently exist that, even with perfect data quality, would be able to replace bottom up cost assessments for most activities involved in running a NSP. (pp. 8–9)</p> <p>MEU: Yes. Agrees that the current actual costs might not be at the efficient frontier and a check is required to identify if this is the case and by how much costs depart from the frontier. (p. 12)</p> <p>Ergon: The purpose and the objective of the Guideline need to be more clearly defined and reconsidered. The AER provides little indication of how it will apply its task, other than to state that its intended process will be set out in the F&A for each DNSP. The Issues Paper casts a wide net in terms of the data it is seeking to collect, without sufficient clarification on the intended use of this information. (p. 10)</p>
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		<p>PIAC: Previous determinations did not have sufficient rigour in assessment of opex and capex. It is essential that both aggregated and disaggregated benchmarking techniques are expanded effectively and immediately implemented. (p. 8)</p> <p>SP AusNet: Does not agree that the objective should necessarily be to expand the toolkit per se. The objective should be to identify and describe workable and effective techniques that enable the AER to assess the expenditure forecasts put to it by the NSPs against the relevant criteria in the NER. (p. 7)</p> <p>Aurora: No. Benchmarking is properly used as a sanity check, however, the AER (goes beyond this when it) indicates benchmarking will be used to indicate effectiveness of incentive regimes. (p. 3)</p>
		<p>ActewAGL: Very concerned at the AER's suggestion to become less reliant on revealed costs as it increases the use of benchmarking. This is contrary to the EBSS and the NER incentive mechanisms. (p. 3)</p> <p>ENA: The issues paper suggests that previous expenditure allowances may have been set too high, that some NSPs have not responded to the incentive mechanisms, and that benchmarking techniques could be relied upon instead of revealed costs. Notes that there are incentives and requirements outside the NER regulatory regime that affect NSPs' behaviour, such as jurisdiction-specific reliability standards. The extent to which benchmarks could be relied on at any point in time would depend on the confidence that participants, including the regulator, have in the accuracy of the benchmarking techniques and the quality and quantum of supporting data. (pp. 9–10)</p>
<p>Question 5</p> <p>Do stakeholders have views on the use of revealed costs and the reliance on incentive mechanisms, and how this should change with the increased reliance on benchmarking to assess expenditure allowances?</p>	<p>ActewAGL</p> <p>Energy Networks Association</p> <p>Ergon Energy</p> <p>SP AusNet</p> <p>CitiPower, Powercor, SA Power Networks (joint submission)</p> <p>Public Interest Advocacy Centre</p> <p>Aurora Energy</p> <p>Jemena</p>	<p>Ergon: Although useful as an indicative tool, revealed costs can be misleading as benchmarks. For instance, in the exercise of seeking a 'like for like' comparison between DNSPs during a particular period, adjustments are required to ensure comparison is feasible. However, the challenge in undertaking this exercise is to determine what are reasonable adjustments to make and whether the same adjustments should be made for all DNSPs, or applied based upon the unique circumstances of the DNSP. (p. 8)</p> <p>SP AusNet: Does not consider that the use of benchmarking to inform regulatory decision-making in the context of a building block regime alters the nature of the regulatory regime as set out in the NER. Therefore, the increased use of benchmarking within the building block regime would not give rise to any changes in the use application of the incentive mechanisms that have been established within that regime. (pp. 8–9)</p> <p>CP/PC/SAPN: The Issues Paper suggests that not all DNSPs have responded to the incentive mechanisms. As evidence, they point to the trend for some DNSPs to overspend. However, spending at a level in excess of the AER's expectations does not necessarily suggest inefficiency or imply a lack of response to incentives. The 'problem' of differing responses to incentives needs analysis into the causes and possible solutions to the problem. The Issues Paper suggests that it potentially could abandon incentives and use only economic benchmarking and category based techniques. Consider this to be an inappropriate approach. The existing carry-over and incentive mechanisms ensure that regulatory decisions remain effective despite significant changes in the industry environment (e.g. technological change). (Attachment A, p. 3)</p> <p>PIAC: If the AER approves allowances that are above reasonable expenditure requirements, NSPs are not being rewarded for efficiency gains. Recent determinations indicate that the revealed cost approach has not been effective in identifying efficient expenditures in base or forecast years. There are incentives for NSPs to inflate their forecasts, putting the onus on the AER. In this context the revealed cost method can provide some insights although on its own it cannot drive productivity improvements in NSPs. The expansion and immediate implementation of aggregated and disaggregated benchmarks is</p>

essential. (pp. 8–9)

Aurora: Benchmarking and revealed costs both have a role to play but do not necessarily indicate what is a reasonable forecast for an NSP, due to changing circumstances and differences between NSPs. Incentive schemes drive a certain behaviour, but it is uncertain why the AER would stop using them in the context of its recent comments during the rule change process and given benchmarking also uses some revealed costs. Additionally, incentive schemes pre-suppose NSPs won't act without financial impact, which does not reflect its own case where its Government owner is pushing for lowest sustainable costs. (p. 4)

Jemena: Disagrees with the implication of question 5 that benchmarking might in some way be a substitute for incentive mechanisms. Incentive regulation was devised precisely because of the problem that confronts the regulator – that efficient costs for a business cannot be identified by inspection or analysis. (p. 6)

<p>Question 6</p> <p>Are there any other principles that you think that should be added to this list? Should we include principles that guide the selection of the assessment techniques to be applied in the framework and approach stage, from the list of appropriate techniques (that will be outlined in the Guideline? If so, do you think that the principles outlined here provide appropriate guidance on technique selection?</p>	ActewAGL	ActewAGL: Generally supportive of the AER's principles, but considers the costs of regulation (i.e. data requirements) should not outweigh the benefits. (p. 2)
	CitiPower, Powercor, SA Power Networks (joint submission)	CitiPower/Powercor/SAPN: (In relation to benchmarking) methodologies and data set must be audited, transparent and replicable. The principles outlined by the AER are very high level and offer little guidance to NSPs as to the approach the AER will adopt in a given set of circumstances. They also do not reflect the expenditure factors. They are supportive of the AER's view that techniques should enable NSPs to form a view on forecast expenditure that is objective, unbiased, transparent and reliable. Principle 1 seems to be encouraging ongoing efficiencies, which may impose arbitrary blanket efficiency targets over the regulatory period. (pp. 7–10, Attachment A, pp. 4–5)
	Major Energy Users Inc.	MEU: The AER's list of principles is a good starting point but all techniques should be retained in AER's armoury. Use the most appropriate tool for the circumstances and explain why one tool is selected over another as part of the decision process. (pp. 13–14)
	Energy Networks Association	ENA: These principles seem reasonable in guiding the AER's selection of assessment techniques, with some clarifications. The guidelines should provide a clear decision framework for how expenditure assessments will be undertaken—explaining what technique will be used in what circumstances and how that decision will be made. The guidelines should explain when and how the AER will use techniques so NSPs can target their proposals towards meeting relevant regulatory tests in light of the AER's approach. Principle 2 should include transparency, due process and the relative precision of information sources. Principle 3 should include the need to ensure selection does not impose significant cost on NSPs to gather data. (p. 11) ⁵³⁶
	EA Technology Australia	EA Technology: Principle 4 suggests we would use techniques that examine only changes to an NSP's operating circumstances. Consideration should be given to including guidance that ensures the application of this principle does not lead to the use of approaches that overly simplify analyses in the interests of expediency. Two additional principles should be included:
	Ergon Energy	
	SP AusNet	
	Public Interest Advocacy Centre	
	VIC DNSPs (joint submission) (Powercor, CitiPower, SP AusNet, Jemena, United Energy)	

⁵³⁶ Supported by: NSW DNSPs (p. 2), Ergon (p. 4), Jemena (pp. 1-2), Vic DNSPs (pp. 1-2), SP AusNet (p. 1), CP/PC/SAPN (p. 1), Grid Australia (p. 1), UED (pp. 5-6).

where differences are likely, all relevant techniques should be applied with preference given to those with lower uncertainty, to avoid the perception of bias; and

techniques should provide both short and long term views of how expenditure relates to service levels experienced by the consumer. Reference to the long term interests of consumers would be a useful principle (pp. 1–2)

Ergon: Support for principles that focus on how the AER is likely to form a view of a satisfactory forecast, having regard to expenditure assessment. In general, reiterates the PC's view that processes should be:

- Transparent;
- Capable of maximising learnings;
- Involve international collaboration; and
- Involve peer review of processes and be subject to regular consultation with stakeholders. (pp. 5, 8–9)

SP AusNet: Generally accepts AER's principles, subject to:

Principle 1 need not distinguish between assessing expenditure and efficiency

Principle 2 should explicitly state that techniques should be replicable by third parties including NSPs

Principle 3 should explicitly commit the AER to not pursuing techniques that would place inordinate cost or administrative burden on NSPs in providing data. (pp. 9–11)

PIAC: Supportive of principles, suggests they be framed in the context of the NEO, e.g. long term/ whole of life perspective. Agrees with principle 1, also with the distinction between assessing efficiency and forecasting (although these are linked). Notes principles 2, 3 and 5 would focus on comparison using actual or realised data and to limit the level of detail and complexity of analysis. Supports principle 4 in considering changes to variables rather than rebuilding those circumstances. (pp. 9–10)

Aurora: Supports the listed principles, but considers the inclusion (in Principle 2) of finding a benefit in using subjective project review creates uncertainty and could be deleted. (p. 5)

Vic DNSPs (Attachment C): Implementation of new analytical techniques should be assessed with these criteria:

- Robustness
- Transparency
- Promotion of efficiency
- Consistency with wider regulatory framework

		<ul style="list-style-type: none"> Reasonableness of data requirements and costs involved Adaptability to changes in network output requirements. (p. iii)
Question 7	Energy Networks Association	<p>ENA: Expenditure benchmarks are useful tools in providing a high-level reasonableness view of businesses' overall expenditure forecasts. Expenditure benchmarks should be used as an informative rather than deterministic tool, to guide investigations. (p. 12)</p> <p>Ergon: Expenditure benchmarks are useful as informative rather than deterministic tools, as a means of highlighting areas for further investigation, and as starting points for dialogue with DNSPs regarding justifications for levels of opex and capex incurred/proposed. Risks where models are applied without consideration of cost drivers (including economies of scale/scope) and where input data are inadequate (including assumptions about homogeneity of sample data). (p. 9)</p>
Are there any assessment techniques that should be considered as forming part of the guidelines? What are the relative benefits and shortcomings of each of the approaches and how could the latter be addressed?	Ergon Energy	MEU: In relation to capital investment, many firms use the available capital as the upper limit of capital investment. Essentially, this upper limit is defined by how much new capital can be borrowed (debt) and is available for retention from declared profits. Considers that this is a technique that should be applied to total capex. Not aware of other techniques used to justify an expenditure allowance other than the arbitrary cost reduction process e.g. headcount reduction. (pp. 14-15)
	Major Energy Users Inc.	
	SP AusNet	SP AusNet: As noted in question 6, it would be helpful if the Guidelines were to set out how the AER will select the particular approaches it proposes to apply to each subset or category of expenditure. (p. 11)
	Public Interest Advocacy Centre	PIAC: Suggests AER consider (where detailed/ engineering analysis is chosen) the relative cost of the service element and its impact on quality of service/ long term interest of consumers. Also apply more scrutiny to those forecasts that are significantly above historic levels, and for NSPs that have a track record of over-forecasting expenditure requirements. The prospect of less intrusive methods for NSPs that provide accurate forecasts may be seen as a reward. (pp. 10-11)
	Aurora Energy	Aurora: Guidelines should not prescribe the use of any particular method, each has relative merits. Expresses some concern with misuse of individual methods, either due to inadequate data inputs or wrong method for the data. (p. 5)
Question 8	Aurora Energy	Aurora: Does not consider there is merit in attempting to derive quantitative relationships between expenditure and drivers. Any relationship derived from a robust function will be impossibly complex and any usable function would be based on unrealistic assumptions. The AER does not make a case for disaggregating expenditures, recent changes to NER removed the need for the AER to consider disaggregated expenditure proposals. (pp. 5–6)
Do stakeholders agree with our general approach of attempting to derive quantitative relationships between expenditures and drivers? Are there better, more cost effective alternatives to assessing disaggregated expenditures?	Energy Networks Association	ENA: Supports the general approach of attempting to derive quantitative relationships between expenditures and drivers. The AER must however ensure that it has identified all of the expenditure drivers to ensure a business is funded to meet all its obligations. (p. 13)
	Ergon Energy	Ergon: The provision of network services is a complex balancing act, and the relationship between the drivers and the requirement for expenditure in different activities that support the provision of services and meet customer expectations are not always direct or immediately observable. (p. 10)
	SP AusNet	SP AusNet: Supportive of the AER's general approach of attempting to derive quantitative relationships between expenditures and drivers, noting this is likely to be more applicable to distribution businesses. It will be important for the
	Public Interest Advocacy Centre	

		<p>AER to progress its work in this area having regard to the different characteristics of the transmission and distribution sectors. (pp. 11-12)</p> <p>PIAC: Strongly supports more quantitative assessments of the relationships with drivers, noting the reasons quoted for recent increases in allowances (demand, replacement and reliability standards) in addition to claims around network scale. Scale effects also raise questions around the impact of ownership structure. Some relationships could be investigated through statistical, sampling and engineering investigation, noting Ofgem's approach to higher level expenditure regressions. (pp. 11-12)</p>
<p>Question 9</p> <p>Do stakeholders have any in-principle comments about the level of expenditure disaggregation given our expectation that lower levels of aggregation e.g. by asset type, are likely to be conducive to more robust benchmarking and other quantitative analysis?</p>	<p>Aurora Energy</p> <p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Major Energy Users Inc.</p> <p>SP AusNet</p> <p>Public Interest Advocacy Centre</p>	<p>Aurora: Errors compound, i.e. forecasts based on disaggregated expenditures, when aggregated, will have a larger error term. (p. 6)</p> <p>ENA: Comfortable with aggregation at an asset type level. However, the AER must be cognisant that obtaining unit costs and volumes for each asset type will not necessarily provide robust data for the purposes of benchmarking in the short to medium term. (p. 13)</p> <p>Ergon: Disputes the general assumption that lower levels of aggregation will be more conducive to robust benchmarking/quantitative analysis. Obtaining unit costs and volumes for each asset type will not necessarily provide robust data. (p. 10)</p> <p>MEU: The separation of costs into defined cost centres is the very basis of proper cost control, and all competent firms will carry out such segregation of costs. Whilst different firms will have differing cost centres, most firms in a similar business will have a large degree of commonality in their cost centre structure. To accept that imposing a need for commonality is too difficult does not recognise this commonality is basic to sound regulation. (p. 16)</p> <p>SP AusNet: The extent to which lower levels of aggregation lead to more robust benchmarking is an open question, and it depends on the availability of reliable, sufficiently abundant and consistent data across NSPs. Ensuring consistency of data across NSPs within transmission and distribution sectors is critical to producing robust analysis. (p. 12)</p> <p>PIAC: Notes that benchmarking may be robust in some instances of disaggregated expenditure analysis, though analysis of aggregated data may be robust as errors are averaged out. A combination of aggregated and disaggregated analysis is the key to a robust process. (p. 12).</p>
<p>Question 10</p> <p>Do stakeholders agree that economic benchmarking will be an important adjunct to more detailed expenditure assessments?</p>	<p>Aurora Energy</p> <p>CitiPower, Powercor, SA Power Networks (joint submission)</p> <p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Major Energy Users Inc.</p> <p>SP AusNet</p>	<p>Aurora: EBT may be an important adjunct to category assessments, impossible to tell as it hasn't been implemented yet. (p. 6)</p> <p>CP/PC/SAPN: Agree that economic benchmarking will be an important adjunct to more detailed expenditure assessments. However, economic benchmarking should only be used to inform the AER of a 'reasonableness view' of expenditure and should not be used in a deterministic manner. (pp. 7-8)</p> <p>ENA: Agrees that economic benchmarking has potential to be an adjunct to more detailed expenditure assessments. However, as noted in the response to question 7, economic benchmarking should only be used to inform the AER of a reasonable level of revenue, and only to the extent to which it relates closely to the cost drivers of NSPs. It should not be used for deterministic purposes. (p. 14)</p>

Public Interest Advocacy Centre

Ergon: Believes comparison is the primary purpose for which benchmarking should be used, as a means to guide where further investigation is required, not as an expenditure setting mechanism. (p. 10)

MEU: Emphatically yes. The absence of the implementation of this tool has been a major failing in the AER process to date. Welcomes the extension of the expenditure forecast that this will introduce. (p. 17)

SP AusNet: Agrees that the economic benchmarking techniques identified by the AER certainly have the potential to complement category-based analysis by:

- providing an overall and higher-level test of relative efficiency;
- facilitating benchmarking which may not be possible as part of the category analysis; and
- cross-checking or reinforcing findings that are made through other types of analysis. (p. 13)

PIAC: The progressive introduction of economic benchmarking is essential to the process of economic regulation. It is to the benefit of all parties that aggregate assessments become progressively more significant as part of the overall determination by the regulator. (p. 12)

Expenditure assessment process

Question 11

Do stakeholders agree that the first-pass process described above is a useful and appropriate application of expenditure assessment techniques?

Energy Networks Association

Ergon Energy

SP AusNet

Public Interest Advocacy Centre

Aurora Energy

United Energy, Multinet (joint submission)

ENA: While supportive of the first-pass approach, if it is not done properly (e.g. without rigour or supporting information) could be misleading. Also considers category level analysis should be limited to high levels of aggregation where there is less potential for different interpretation and cost allocations to affect data. (pp. 14-15)

Ergon: This process provides stakeholders with early notification of potential areas of concern with the accuracy of expenditure forecasts, and provides the opportunity for more evidence to be provided in relation to targeted areas. Suggests limiting category analysis to high level of aggregation to avoid distraction in the detail of how tools are applied at the expense of exposing issues. (pp. 10-11)

SP AusNet: If the assessment is genuinely a 'first pass', then the basis of the assessment must be explained fully so that all stakeholders understand how and why the Draft and Final Decisions may differ materially from this provisional assessment. (p. 14)

PIAC: Supports first pass approach, particularly as it provides stakeholders with access to objective and transparent performance data, thus giving them a better opportunity to query NSPs prior to the draft determination. This is particularly important given current policy context trying to improve consumer engagement in regulatory decisions. (p. 13)

Aurora: Supports the first pass model, raises concerns about resource implications. This process will reduce the time available for the AER and NSPs to process information and respond to information requests. Based on its own experience in the recent review, early engagement with the AER's engineering consultant would also have been beneficial to all. (p. 7)

UED: The 'first-pass' approach will only be beneficial if the timelines allow for the review to be undertaken with sufficient rigour and published with sufficient supporting information to not mislead consumers. (p. 8)

Expenditure incentive schemes and their application

<p>Question 12</p> <p>Do stakeholders have any views on the relationship between the assessment tools that we have identified, and our existing incentive schemes? Given the interrelationship between the two, and that our incentive schemes are to be revised over 2013, what processes should we follow to ensure there are appropriate incentives on NSPs to make efficiency gains, while at the same time implementing appropriate expenditure assessment techniques?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>SP AusNet</p> <p>Public Interest Advocacy Centre</p> <p>Aurora Energy</p>	<p>ENA: Any benchmarking that leads to an efficiency adjustment to the base costs will dilute the sharing of efficiency gains or losses, undermining stakeholder confidence in the potential rewards or penalties that exist under the scheme. This uncertainty may ultimately render the incentives under the scheme ineffectual. (p. 15)</p> <p>Ergon: As revealed costs methodology for opex and benchmarking do not naturally align, Ergon has concerns that, where the AER makes efficiency adjustments to base costs, the result will be a dilution of the efficiency gains/losses, in turn undermining the EBSS scheme. (p. 11)</p> <p>SP AusNet: A question arises as to whether the use of benchmarking to set expenditure allowances makes the incentive properties of the EBSS redundant. It is conceivable that this may be the case where expenditure benchmarks are set independently of the company's own performance. However, the NER do not provide for this form of regulation, and therefore the question should not arise in relation to the current expenditure guidelines. (p. 14)</p> <p>PIAC: In light of recent data (e.g. PC) showing declines in NSP productivity in recent years, is sceptical that the EBSS has delivered on its objectives across all NEM jurisdictions. Hopes that review of incentives over 2013 addresses this issue. Expects incentive strength to increase over time. Also suggests incentive strength be tied to benchmarking performance outcomes for particular NSPs. Notes excess WACC contributes to capex overspending incentive so suggests both incentives and WACC be considered in tandem. (pp. 13–14)</p> <p>Aurora: Where there is no confidence incentives are resulting in efficient costs being revealed/ used, benchmarking is a comparison of peer-groups, rather than a useful tool for assessing forecasts. Hence is uncertain why the AER would seek to limit the application of incentive schemes. (pp. 7–8)</p>
<p>Question 13</p> <p>Do stakeholders have any comments on how best to manage the interrelationships between the guidelines, F&A processes, determinations and annual benchmarking reports?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>SP AusNet</p> <p>Public Interest Advocacy Centre</p>	<p>ENA: Annual benchmarking reports and determinations need to be based on consistent data across all NSPs in order to make valid benchmarking comparisons. (p. 15)</p> <p>Ergon: Believes the introduction of benchmarking techniques should be incrementally implemented over a reasonable timeframe, which will lower the risk of perverse outcomes in any single determination, and allow for a measured, monitored establishment. (p. 11)</p> <p>SP AusNet: There are no particular issues of concern regarding the interrelationships between the Guidelines, F&A processes, determinations and annual benchmarking reports. The AER's Issues Paper appears to inappropriately suggest that these components of the regulatory process ought to be amended in response to information provided by NSPs. (p. 15)</p> <p>PIAC: Would be concerned if these difficulties/ transitional issues (also identified in questions 14 to 19) slowed the progress of implementing benchmarking, noting these tools would need to be qualified in the next round of determinations. Parties must accept this is an evolutionary process with ongoing dialogue between all parties. This process must be controlled with directions of change clearly signalled ahead of implementation. New approaches should be subjected to more scrutiny than would be applied in any one determination process. Claims made by NSPs regarding the cost of providing new information should be closely scrutinised, noting recent examples of allowances for IT capex in recent decisions, which should make reporting systems adaptable to change. (pp. 15-16)</p>

Question 14	Energy Networks Association	ENA: Information from RINs needs to be evaluated and compared with the data requirements of any selected benchmarking methods. AER needs to manage the implementation of benchmarking as a technique and commit to a cycle of review and improvement. (p. 16)
How would it be best to maintain a degree of consistency in assessment techniques and associated data reporting, while at the same time allowing improvements in techniques?	Ergon Energy	Ergon: In recognition of the current RIN requirements, and the extensive data collated as a result, benchmarking ought to be introduced in a managed way, with an extended period of review and process improvement, enabling implementation in an evolutionary manner. (p. 11)
	SP AusNet	SP AusNet: Expects the application of techniques to be refined over time as new data become available. It is not clear that there should be any consistency issues arising from the assessment techniques and data reporting. (p. 15)
	Public Interest Advocacy Centre	PIAC: See response to Q13
	Aurora Energy	Aurora: The AER has significant amount of data from pricing reviews and from annual RINs. This should form the basis of the AER's information requirements. (p. 8)

Question 15	Energy Networks Association	ENA: Sees no problems with the sequencing of events as specified in the NER. The individual processes should exist in an integrated framework that minimises duplication of effort and contributes to an enhanced understanding of cost drivers and efficient costs. The F&A process should recognise the weight to be placed on a particular technique where it becomes is apparent that sufficient data are/ are not available or where data do/ do not support the existence of relationships between cost drivers and expenditure. (p. 16-17)
Are there any ways the expenditure assessment process, including in preparing NSP forecasts, could be improved by linking the Guidelines, the F&A process and the NSP's obligation to notify us of its forecasting methods?	Ergon Energy	Ergon: Sees no issues with the sequencing of events as specified in the Rules. However, each of the individual processes should exist within a coherent, integrated framework that minimises duplication of effort and contributes to an enhanced understanding of an NSP's cost drivers and efficient costs. (p. 11)
	SP AusNet	SP AusNet: It is unclear why the Guidelines should be linked to the NSP's obligation to notify the AER of its forecasting method in the manner suggested by the question. The same comment applies to the F&A process. The NER establish the linkages between the various regulatory processes. (p. 16)
	Public Interest Advocacy Centre	PIAC: See response to Q13

Detailed timing and transitional issues

Question 16	Ergon Energy	Ergon: Recommends that the AER keep in mind the implementation time required by DNSPs which do not currently have in place the systems to commence recording data in the format required to meet RIN requirements. Once system changes have been implemented, suggests that the timing of the issuing of RIN templates should take into consideration each business' regulatory year and regulatory control period (p. 12)
Keeping in mind the preference to use up to date and nationally consistent data in all benchmarking analysis, what would be the best time to issue RIN templates? Would these need to be for all NSPs? How frequently should we do this?	Major Energy Users Inc.	MEU: All NSPs should commence collecting the data in the format required as soon as possible, even though application to their specific revenue rest might be some time away. (p. 20)
	SP AusNet	SP AusNet: Appreciates that differences in companies' reporting cycles may create some issues in relation to the production of an annual benchmarking report. However, does not consider that this warrants updating the report outside the
	Energy Networks Association	
	CitiPower, Powercor, SA Power Networks (joint submission)	

Public Interest Advocacy Centre annual production process. (p. 16)

Aurora Energy ENA: RIN timing for each business should continue to align with each business's regulatory year and regulatory period cycle. The issues paper appears to anticipate a need for all data to be collected at the same time across the country in order for results to be comparable. In reality, it is unlikely that data collected will have such a degree of accuracy that timing differences in the collection of data between NSPs will have a significant impact on the comparability of data. The required degree of consistency will take several iterations to achieve and the annual RIN process will need to support an evolutionary development of the data requirements. Simply setting out consistent definition is not sufficient, as it takes time for businesses to align their operational and financial processes to new definitions. Also, it will take time to understand whether all businesses are interpreting the definitions in the same way. (p. 17)

PC/CP/SAPN: As per ENA's response (p. 9)

PIAC: See response to Q13

Aurora: RINs should be issued as soon as possible to give NSPs sufficient time to clarify the AER's requirements and make required information system changes. The timing/ issuing of notices should align with a NSP's regulatory years and periods. (pp. 8–9)

<p>Question 17</p> <p>Should we try and limit the collection and analysis of benchmarking data to annual benchmarking reports? Alternatively, should we focus our effort on benchmarking analysis at each draft and final decision stage, with less attention to annual benchmarking reports?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Major Energy Users Inc.</p> <p>SP AusNet</p> <p>Public Interest Advocacy Centre</p> <p>Aurora Energy</p> <p>CitiPower, Powercor, SA Power Networks (joint submission)</p>	<p>ENA: The NER are clear that the AER must take account of its most recent annual benchmarking report when assessing a regulatory proposal. (p. 18)</p> <p>Ergon: The AER must take into account the most recent annual benchmarking report when assessing a regulatory proposal. (p. 12)</p> <p>MEU: No, data should be collected from all NSPs on an annual basis. Even though the data collected for an NSP which is not about to undergo a revenue review, the data provided by it is useful for assessing performance of another NSP that is undergoing a review. Annual comparison work of all NSPs will provide useful input to stakeholders examining revenue review documentation. Therefore the AER should carry out its benchmarking performance analysis of all NSPs every year and make this information public. (p. 20)</p> <p>SP AusNet: The annual benchmarking report should inform the determination process as envisaged by the NER. (p. 16)</p> <p>PIAC: See response to Q13</p> <p>Aurora: Supports limiting data collection and analysis to benchmarking reports. Doing otherwise diminishes the value of these reports. (p. 9)</p> <p>CP/PC/SAPN: It is not practical to limit the collection and analysis of benchmarking data to annual benchmarking reports. The appropriateness of benchmarking analysis for the purposes of assessing expenditure forecasts will inevitably turn on the particular proposals and thus will always need to be assessed at the regulatory review process stage. (Attachment A, p. 10)</p>
<p>Question 18</p> <p>Are there alternative, more flexible</p>	<p>Energy Networks Association</p>	<p>ENA: The annual RIN process provides ample opportunity to gather all required data. Any data for regulatory purposes, including benchmarking, should ideally be collected through the evolution of current formal RIN processes. (p. 18)</p>

means to gather data for benchmarking purposes in annual reports and in determinations, such as requests outside the NEL provisions?

Ergon Energy
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Ergon: Does not believe data gathering mechanisms beyond those provided for the in the NEL are necessary. The current RIN processes provide ample opportunity to gather any required information. (p. 12)

MEU: Has doubts that NSPs will comply with requirements that are not enforced under the NEL. There is also a concern that NSPs will seek to be reimbursed for providing such data raising the concern as to the value for money that such data will provide. (p. 21)

SP AusNet: It is essential that the AER does not add to the regulatory burden by increasing its information requests, either in terms of content or frequency. As already noted, the value of the annual benchmarking report over time will be enhanced if few changes are made to cost categories and definitions. (p. 16)

PIAC: See response to Q13

Aurora: The AER has extensive information gathering powers so ad hoc requests are always possible. Aurora notes that the EBSS restricts opex of distributors such that expenditure on information reporting (which is significant and borne by consumers) is diverted from the maintenance of network assets. (p. 9)

CP/PC/SAPN: All information provided to the AER must be robust. Even information provided on a more informal basis that does not require formal sign off would still need to be fully reconcilable with information produced in response to regulatory processes. (Appendix A, p. 10)

Question 19

Should we be considering the alignment of regulatory years and of regulatory control periods for transmission and distribution NSPs to overcome some of these challenges? If so, should regulatory years reflect the Australian financial year? How would the alignment of regulatory control periods be best achieved?

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ENA: It is not necessary to align regulatory control years and periods for transmission and distribution NSPs, or to align regulatory years with financial years. There is no practical reason why the AER's analysis should not be based on the most recently reported data for each business. There is no consistency even between financial years across businesses, for example as some are overseas owned with financial years in the shareholder's jurisdiction being different to the Australian financial year. The staggered nature of regulatory periods provides an opportunity for regular review of the effectiveness of the benchmarking and assessment process and to include learnings from one revenue determination into the process applied to the following determination. The introduction of a range of new expenditure assessment techniques in a wholesale manner would represent a significant change for both the AER and the NSPs, and would need to be managed effectively if it is to be successful and result in the outcomes desired by the AER. A process whereby smaller incremental steps are taken and the results assessed and processes modified accordingly is more likely to result in a successful implementation. (pp. 18–19)

Ergon: Not convinced that alignment of years (regulatory, financial) is necessary. Having staggered regulatory periods provides an opportunity to review processes and transfer lessons into subsequent reviews. (p. 12)

CP/PC/SAPN: As per ENA's response. (p. 10)

SP AusNet: Varying the reporting cycles is unlikely to have a material impact on the benchmark analysis if some company data relates to calendar years and other data relate to financial years. It is unlikely to be material if some companies provide an estimate for the latest year's data and others provide actual data. (p. 17)

PIAC: See response to Q13

Aurora: The alignment of regulatory periods, if performed, should be achieved by lengthening rather than shortening the

duration of the periods. They note the cost of a distribution determination is significant and passed onto customers. (p. 10)

MEU: Providing that all data covers an entire 12 month period, it is still useful whether collected over a financial or calendar year. Equally, having data collected over the same timeframe is preferable statistically. On balance, the MEU considers that data should be collated over the same periods (i.e. calendar or financial years) as this provides more consistency and comparability of the data collected. (pp. 21–22)

Questions on economic benchmarking techniques—Holistic approach

<p>Question 20</p> <p>We are interested in your views on the holistic approach to the selection and establishing reporting requirements for economic benchmarking techniques.</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>SP AusNet</p> <p>Aurora Energy</p> <p>Jemena</p> <p>Major Energy Users Inc.</p>	<p>ENA: Understands the AER’s desire for flexibility in selecting an appropriate benchmarking technique however, this may come at the cost of additional costs or inefficiencies related to data definition and collection costs. (Attachment A p.3)</p> <p>Ergon: Concerned that there has been insufficient analysis of options undertaken by the AER before proceeding with a holistic review process. In the most recent workshops, the AER seemed to have reached the holistic approach as the only available option open to them. (p. 12)</p> <p>SP AusNet: It is appropriate to adopt a holistic approach to assessing efficiency through benchmarking techniques. It is reiterated that transmission network service providers are much less conducive to benchmarking analysis than electricity distribution businesses. (p. 17)</p> <p>Aurora: No concerns about a holistic approach provided techniques are chosen to fit the data rather than provide a preferred result. (p. 10)</p> <p>Jemena: While this may be an academically interesting and perhaps a logical extension of the very thorough review published jointly by the ACCC and the AER in 2012 there is a serious question whether it is an appropriate approach in the current regulatory context. (p. 5)</p> <p>MEU: Supports the holistic approach. It considers that there is no single approach that will provide the perfect answer. A holistic approach allows for different techniques to become more applicable as more data is collected. (p. 22)</p>
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Questions on economic benchmarking techniques—Efficiency and productivity measurement

<p>Question 21</p> <p>Have we identified all the relevant economic benchmarking techniques and, if not, are there other economic benchmarking techniques that should be considered?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>SP AusNet</p> <p>Aurora Energy</p>	<p>ENA: Although the AER has identified all of the common techniques used for benchmark analysis, this does not mean that they are relevant in the Australian context. Australia has only 15 DNSP’s some of which are predominantly rural and others predominantly urban, with varying levels of load density. (Attachment A p.3)</p> <p>Ergon: Any attempt at benchmarking expenditure assessments (regardless of the technique/s chosen) across DNSPs using high level ratios will be misleading, unless the underlying drivers, inherent costs and cost allocation practices of the expenditures of the quite different DNSP businesses in Australia are taken into account. (p. 13)</p> <p>SP AusNet: The AER’s list is a comprehensive summary of the most relevant economic benchmarking techniques. (p. 17)</p> <p>Aurora: The AER has identified all common benchmarking techniques. (p. 10)</p>
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Question 22

We are interested in your views on how economic benchmarking techniques should be applied in our decision making process regarding expenditure. Specifically, we are interested in your views on:

—using these techniques to assist us to form a view on the efficiency of base expenditure and expenditure forecasts

—measurement of the likely pace at which productivity improvements may be made over a regulatory control period.

Energy Networks Association

Ergon Energy

Major Energy Users Inc.

SP AusNet

Aurora Energy

Energex

ENA: Whilst economic benchmarking techniques may be a useful tool in comparing DNSPs, using it to assess the efficiency of base expenditure or the likely pace of productivity improvements relies on being able to fully account for the cost drivers and circumstances of each of the businesses. Whether this was possible would need to be verified. (Attachment A pp.3–4)

Ergon: Reiterates its position that economic benchmarking cannot be relied upon to provide consistent, reliable information. Whilst useful to provide comparative data, benchmarking cannot fully account for different cost drivers unique to each DNSP and would be inappropriate if used to infer relative efficiency between DNSPs. (p. 13)

MEU: Historically, the revealed cost approach has been based on 4 years of data being considered to be adequate for forecasting. Therefore, after 4-5 years of data collection, there should be sufficient data collected for benchmarking to be considered as the primary tool for assessing whether the proposed expenditure is in relation to the efficient frontier. (p. 23)

SP AusNet: It would not, from a regulatory perspective, endorse the AER employing benchmarking to determine whether actual expenditure is efficient, unless the ex post prudency review provisions for capital expenditure have been triggered. (p. 18)

Aurora: Benchmarking should be used as a screening test to determine whether forecast is plausible and to target detailed assessment. (p. 11)

Energex: Concerned that benchmarking cannot fully account for the inherent and inherited cost drivers unique to each DNSP and in particular the use of the RAB as a primary input to efficient measurements and indicators may result in perverse outcomes. (p. 1)

Questions on economic benchmarking techniques—Inputs, outputs and environmental variables

Question 23

Should the AER separate DNSPs into groups for the purposes of economic benchmarking? If so, how should the groupings be determined?

SP AusNet

Major Energy Users Inc.

Aurora Energy

SP AusNet: It may be appropriate to separate DNSPs into groups. However, this is an empirical question that would need to be tested through the benchmarking analysis. It would be wrong to commence from the premise that DNSPs should be separated into different groups. (p. 18)

MEU: Considers that rather than group NSPs by type, it would be preferable to measure the inputs in terms of similar activity. For example rather than grouping (say) SA Power networks, Powercor, SP AusNet, Ergon and Essential Energy, it would be preferable that the benchmarking data from all NSPs be collected for all NSPs under the four commonly used headings of CBD, urban, rural short, rural long. (p. 24)

Aurora: Benchmarking is only meaningful if used to compare similar entities, requiring grouping of entities which is problematic in the NEM with a limited number of DNSPs. Alternative groupings may include density e.g. value per length or per customer. (p. 11)

Question 24

Are our criteria for selecting inputs appropriate? Are there any additional criteria that should be

SP AusNet

Aurora Energy

United Energy, Multinet (joint submission)

SP AusNet: In relation to the criteria for selecting inputs, notes the following description in the Issues Paper is open to various interpretations: Inputs, and the sub-components of inputs, should be mutually exclusive and collectively exhaustive. As models generally seek to provide a simplified version of reality, SP AusNet questions whether it is appropriate to include a criterion that the inputs should be 'exhaustive'. (p. 18)

Aurora: The table in the issues paper implies the AER intends to model a business in its entirety, which is unconvincingly

added?		<p>complex. (p. 12)</p> <p>UED: Considers both to be non-controversial, however emphasises the need to ensure that the consideration of inputs reflects the decisions made on outputs – that is, they need to be considered in a holistic manner, not in isolation of each other. (p. 8)</p>
<p>Question 25</p> <p>Are the assets and operate and maintain variables appropriate for economic benchmarking?</p>	<p>SP AusNet</p> <p>Aurora Energy</p>	<p>SP AusNet: Agrees that these input variables are relevant to any benchmarking study. However, the challenge in successfully benchmarking performance is to examine the respective inputs and outputs in a meaningful way, given the sometimes significant difference in operating conditions across companies. It is therefore not possible to commit to a particular approach to inputs or outputs without understanding the overall approach and the results of the benchmarking analysis. (p. 19)</p> <p>Aurora: These inputs are inadequate. Would expect differentiation between assets and opex associated with a variety of activities (e.g. transport of power, other network services, building and maintaining network assets, IT or corporate systems). (p. 12)</p>
<p>Question 26</p> <p>What indices can we use to derive price and quantity information for the "operate and maintain" variable for economic benchmarking?</p>	<p>SP AusNet</p> <p>Major Energy Users Inc.</p>	<p>SP AusNet: The discussion on page 64 of the Issues Paper comments that: Labour quantity can also be measured as the labour cost (derived from opex data) deflated by an appropriate labour price index, which may reflect many inter-business differences, such as skill composition and wage rates. It would be easier to use the number of FTE employees as an input. However, it is not clear whether such an approach would be meaningful as it would ignore differences in labour mix, and would also ignore differences in organisation structure including the extent to which services are contracted out. (p. 19)</p> <p>MEU: Independence of index development must be maintained and there should be no adjustments made by the AER or NSPs to maintain the integrity of the index. (p. 25)</p>
<p>Question 27</p> <p>Is the one-hoss shay assumption appropriate for the measurement of capital services provided by individual distribution system assets?</p>	<p>SP AusNet</p> <p>Major Energy Users Inc.</p> <p>Aurora Energy</p> <p>United Energy, Multinet (joint submission)</p>	<p>SP AusNet: The assumption that an asset provides a constant level of service over its lifetime – and by implication requires a constant level of maintenance and condition monitoring – is false. It may, however, be a reasonable working assumption for a particular type of economic benchmarking. (p. 19)</p> <p>MEU: Yes. Has sought advice from its members (which are all capital intensive industries) and the one hoss shay approach is how they approach the measurement of capital services. (pp. 25–26)</p> <p>Aurora: One-hoss shay assumption is appropriate for individual system assets. Actual population failure rates should resemble bath-tub curve. (p. 13)</p> <p>UED: It is recommended that further, detailed analysis be undertaken before any decision is made as to the prevalence of the 'one-hoss shay' assumption for all asset classes, or the extent to which it may apply 'in the main'. (p. 9)</p>
<p>Question 28</p> <p>Does the 'portfolio effect' apply to populations of distribution assets? Assuming the one-hoss shay assumption is appropriate for</p>	<p>SP AusNet</p> <p>United Energy, Multinet (joint submission)</p> <p>Major Energy Users Inc.</p>	<p>SP AusNet: Agrees with the observation in the Issues Paper that the portfolio effect of different asset lives may affect the validity of the one-hoss shay assumption. It is not appropriate to make a decision a priori that the portfolio issue should be ignored. (p. 20)</p> <p>UED: See Q27, The same applies to the extent to which there may or may not be a portfolio effect. (p. 9)</p>

individual assets, does the portfolio effect negate the one-hoss shay assumption when using populations of assets in economic benchmarking?

MEU: No, the portfolio effect tends to enhance the one-hoss shay effect as small amounts of capex can increase the overall output beyond the apparent value of the investment. (p. 26)

Question 29

If the one-hoss shay assumption does not appropriately describe the deterioration profile of DNSP assets, which deterioration profile is most appropriate?

SP AusNet

SP AusNet: Refer to answers to questions 27 and 28. For the reasons already provided, does not support a particular deterioration profile. (p. 20)

Question 30

Should we measure asset quantities using physical or value based methods?

SP AusNet

SP AusNet: Both approaches may be valid, but the gross replacement value of the asset base provides a valid representation of the long term capital costs paid for by customers. For this reason alone, it does not seem appropriate to prefer a physical measure of the capital base. (p. 20)

Aurora Energy

Aurora: It is imprudent to lock in a method; the choice of measurement depends on result sought and assets measured. (p. 13)

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UED: If physical quantities are used as the means of valuing the stock of capital used by DNSPs, this needs to be focused at levels that are consistent with the attributes that lead to changes in the provision of the outputs utilised for the purposes of the economic benchmarking approach. (p. 9)

Major Energy Users Inc.

MEU: Physical measures are less transient than value based measures, as value based measures are eroded by inflation and new technology. Physical measures are eroded by productivity but this is less influential than value depreciation. (p. 26)

Question 31

Assuming the one-hoss shay assumption is appropriate for individual distribution assets, would the existence of the portfolio effect render the use of physical measures of capital quantities inappropriate for economic benchmarking?

SP AusNet

SP AusNet: Considers that different approaches should be tested by conducting alternative benchmarking approaches. (p. 20)

Aurora Energy

Aurora: A general answer to this question is not possible and would vary according to data. (p. 14)

Question 32

How should we derive the value of a DNSP's capital stock for the purpose of determining quantity of

Aurora Energy

Aurora: It should be the undepreciated, unoptimised value of assets used in the system. Depreciation is irrelevant given One-hoss shay assumption. (p. 14)

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MEU: Depreciation of an asset value is a financial approach to recovering the actual investment. Depreciation of an asset does not impact its ability to produce the output. Therefore the value of the asset's ability to produce should not be

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assets?	submission)	depreciated value. Therefore a depreciated replacement cost is not a surrogate for the capital stock. (p. 27) UED: If physical quantities are used as the means of valuing the stock of capital, this needs to be focused at levels that are consistent with the attributes that lead to changes in the provision of the outputs utilised for the purposes of the economic benchmarking approach. (p. 9)
Question 33 What index should be used to inflate historical asset prices into real terms?	SP AusNet Major Energy Users Inc. Aurora Energy	SP AusNet: Conceptually, it is inappropriate to regard one company as more efficient than another because its assets are older and were purchased at a time when asset prices were substantially lower. On this basis, a reasonable approach is to calculate the current replacement cost of the asset base. (p. 20) MEU: The AER should develop a specific index which reflects the actual movements in labour and materials used by NSPs and use this to adjust annual price movements. This would be more exact, remove the risk to consumers and NSPs and avoid the inevitable conservative allowances that currently are built into allowed revenues. (p. 28) Aurora: Whatever index used should reflect the difference between historical and current installed asset costs. (p. 14)
Question 34 Is RAB depreciation an appropriate measure of the annual contribution of capital to the provision of outputs?	SP AusNet Major Energy Users Inc. Aurora Energy United Energy, Multinet (joint submission)	SP AusNet: RAB depreciation may be affected by the changes in asset prices over time, in addition to the assumed remaining life of the asset as noted in the Issues Paper. However, RAB depreciation is likely to be a useful starting point for measuring the annual capital input. (p. 21) MEU: No. This approach attempts to relate two different value elements developed for different purposes. Depreciation is the recovery over time of an investment made – it has no relationship to the outputs that are achieved. (pp. 28–29) Aurora: There is a range of issues that result in RAB depreciation being inappropriate, e.g. fully depreciated assets still in service and past optimisations. (p. 14) UED: The use of the RAB to value a business' sunk capital stock is unlikely to provide a reasonable basis, as the methodology used to derive the original starting value is likely to have deviated away from a cost based approach. (p. 9)
Question 35 What prices should be used to weigh assets and the activities involved in operating and maintaining those assets?	SP AusNet Major Energy Users Inc.	SP AusNet: In terms of the costs of procuring an asset, efficiency measures should not be influenced by the impact of price changes over time. Having said that, a source of cost difference between companies is the effectiveness of their procurement policies and their efficiency in project management. It would not be appropriate to adopt a benchmarking approach that disregarded these important differences. (p. 21) MEU: Actual cost adjusted to a common point in time is the best indicator of the output value of the capital stock. (p. 29)
Question 36 Do the prices of inputs materially differ across jurisdictions within Australia, or could the AER use the same prices as weights for inputs across jurisdictions?	Major Energy Users Inc. Aurora Energy	MEU: Why would they? The only cost element that might be affected would be the cost of installation which depends on location. This can be overcome by subdividing costs into the four basic subgroups of CBD, urban etc. (p. 30) Aurora: It is not appropriate to use the same prices as input weights unless the prices are the same across jurisdictions. (p. 15)

<p>Question 37</p> <p>Are our criteria for selecting outputs appropriate? Are there any additional criteria that should be considered?</p>	<p>SP AusNet</p> <p>Major Energy Users Inc.</p> <p>United Energy, Multinet (joint submission)</p>	<p>SP AusNet: The output criteria appear to be reasonable. (p. 21)</p> <p>MEU: Generally, yes. Connection should be readily definable in terms of numbers and the four basic sub elements (CBD, urban, etc.); replacement could be assessed in terms of reliability. (p. 30)</p> <p>UED: The AER's proposed criteria appear non-controversial. The only subtlety is whether customers should be broadened to the 'community'. Further, the ultimate empirical performance of the particular output variables in econometrically estimated cost functions, or in other models, should also be an explicit criterion. (p. 10)</p>
<p>Question 38</p> <p>If customer numbers are used as an output for economic benchmarking, should these customer numbers be separated into different classes? If so what are the relevant customer classes for the purpose of economic benchmarking?</p>	<p>SP AusNet</p> <p>Aurora Energy</p> <p>Major Energy Users Inc.</p>	<p>SP AusNet: It is reasonable to consider 'numbers of customers served' to be an output for a DNSP. It may be appropriate to distinguish between categories of customers, although the added complexity of doing so needs to be weighed against the improved explanatory powers of the resulting analysis. (p. 21)</p> <p>Aurora: Customer numbers are not an output but meet the criteria of an economic variable, as does peak demand. (p. 15)</p> <p>MEU: Yes. The impacts of different customer classes on networks are significant. The allocation should reflect the impact each has on the network – e.g. kW in terms of electricity networks and MHQ or MDQ in terms of gas networks. (p. 30)</p>
<p>Question 39</p> <p>Have we identified all the relevant outputs? Which combination of outputs should we use in economic benchmarking?</p>	<p>SP AusNet</p> <p>Major Energy Users Inc.</p>	<p>SP AusNet: From a first pass assessment, outputs should reflect the outputs of building block regulation (functional outputs), rather than billing, as this is more reflective of business cost drivers. However, it is inappropriate to conclude which output measures should be adopted without giving due consideration to the results of the benchmarking analysis. (pp. 21–22)</p> <p>MEU: Generally yes. Peak demand by each connection is the prime driver of what the network requires to provide, subject to appropriate recognition of diversity. (p. 30)</p>
<p>Question 40</p> <p>Despite multiple studies using volume of energy delivered as an output, we are not convinced that this is appropriate. What are stakeholder's views on the use of energy delivered as an output?</p>	<p>SP AusNet</p> <p>Aurora Energy</p> <p>Major Energy Users Inc.</p> <p>Jemena</p>	<p>SP AusNet: Would not dismiss volume of energy delivered as an output at this early stage of the AER's process, however it is clearly less relevant than the outputs discussed at question 39. Further, volume of energy delivered may be a useful explanatory variable, even if it is not regarded as an output in a technical sense. (p. 40)</p> <p>Aurora: Energy delivered is not relevant for planning or operation, but for energy not delivered in a reliability sense. (p. 16)</p> <p>MEU: Whilst energy used is the measure that consumers assess their costs by, it is not the main driver of investment needed in a network. (p. 31)</p> <p>Jemena: More relevant measures of utilisation and efficiency for a DNSP is how much spare capacity there is relative to forecast maximum peak demand and how efficiently the business is managing actual installed capacity. (p. 10)</p>
<p>Question 41</p> <p>It would appear that much network expenditure is ultimately intended to maintain the reliable supply of</p>	<p>SP AusNet</p> <p>Aurora Energy</p> <p>Major Energy Users Inc.</p>	<p>SP AusNet: Reliability is an important output variable, as it is something which customers value which is reflected in the NER capex and opex objectives. While there are practical challenges in expressing reliability as outputs in benchmarking functions, it is worthwhile trying to overcome these challenges given the importance of reliability as an output. (p. 22)</p>

electricity. This might include the management of peak demand, network capacity and investment to ensure that networks are secure. Given this, is it appropriate to use measures of reliability as an output variable?

Aurora: Reliability measures are of use only when the aspects of reliability are within the NSP's control. (p. 16)

MEU: Yes. Consumers measure the value of the network in terms of amount of energy used and the reliability of supply as measured by SAIDI, SAIFI and other similar measures. (p. 31)

<p>Question 42</p> <p>Are our criteria for selecting environmental variables appropriate?</p>	<p>SP AusNet</p> <p>Major Energy Users Inc.</p> <p>United Energy, Multinet (joint submission)</p>	<p>SP AusNet: Not convinced that it is necessary to adopt the primary driver of costs where there is a correlation with another environmental variable. In particular, it is unclear how the primary cost driver would be identified without conducting some form of benchmarking or econometric analysis. (p. 23)</p> <p>MEU: Yes. (p. 31)</p> <p>UED: Initial view is that it does not see that there is any major issue with the AER's proposed criteria. (p. 13)</p>
<p>Question 43</p> <p>Have we identified all the relevant environmental variables?</p>	<p>SP AusNet</p> <p>Aurora Energy</p> <p>Major Energy Users Inc.</p> <p>United Energy, Multinet (joint submission)</p>	<p>SP AusNet: Ordinarily, environmental variables would be matters that are exogenous to the industry, but nevertheless affect its cost or service performance. For example, topology or weather would be examples of environmental variables. Would not regard variables that are endogenous to the industry – such as number of customers or peak demand – to be regarded as environmental factors. (p. 23)</p> <p>Aurora: Regulatory and legal obligations are also environmental variables. (p. 16)</p> <p>MEU: Yes, although they would be more appropriate when measured against the sub elements (CBD, urban, etc.) and so allow better benchmarking. (p. 31)</p> <p>UED: Economic Insights' Briefing Paper recommends that the following short list be considered for use as DNSP operating environment factors in economic benchmarking studies:</p> <ul style="list-style-type: none"> ▪ Customer density ▪ Energy density, and ▪ Climatic effects. (p. 13)
<p>Question 44</p> <p>Which combination of environmental variables should we use in economic benchmarking?</p>	<p>SP AusNet</p> <p>Major Energy Users Inc.</p> <p>Aurora Energy</p>	<p>SP AusNet: From a first pass assessment, customer density and climate are the environmental variables more relevant to benchmarking. Both can be significant drivers of costs and are outside of the control of the DNSP. (p. 23)</p> <p>MEU: Peak demand, network density. However these should be reduced to the sub elements of CBD, urban, etc. to provide a more reliable measure. (p. 31)</p> <p>Aurora: Not enough information to comment on this question. (p. 16)</p>

Category analysis questions—Expenditure categorisation

Question 45	Do you agree with this list of expenditure drivers? Are there any others that should be added?	<p>Energy Networks Association Ergon Energy SP AusNet Aurora Energy Grid Australia Major Energy Users Inc.</p>	<p>ENA: The ENA agrees with the list of expenditure drivers identified in the issues paper, however noted a number of issues including but not limited to:</p> <ul style="list-style-type: none"> ▪ the relative contribution of, and the interrelationships between, drivers ▪ that network assets can become obsolete before their condition deteriorates ▪ that safety and environment cost drivers associated with legislative changes would generally be captured in the changes in obligations category ▪ there are expenditure drivers resulting from state based regulation which can differ by state. (Attachment B p. 1) <p>Ergon: The list is incomplete. Further industry consultation is required to develop suitable expenditure drivers, and to further understand how each driver should interact with others. (pp. 13–14)</p> <p>SP AusNet: Agrees with the list of expenditure drivers, noting that they relate to DNSPs. (p. 23)</p> <p>Aurora: Considers the list appears sufficient. (p. 17)</p> <p>Grid Australia: Although relevant to transmission, the terminology used in transmission is slightly different. (p. 28)</p> <p>MEU: These should be reduced into exogenous and endogenous categories and further reduced into sub elements of CBD, urban, etc. (p. 32)</p>
Question 46	To what extent do you think the expenditure drivers are correlated with each other? Given this level of correlation, should we examine the impact on expenditure of each one, or can this list be consolidated?	<p>Energy Networks Association Ergon Energy Jemena SP AusNet Aurora Energy United Energy, Multinet (joint submission) Major Energy Users Inc. Grid Australia</p>	<p>ENA: The expenditure drivers identified are not necessarily correlated, and that if they were the extent of correlation would be open to subjectivity resulting in errors due to inconsistency. ...where there is some correlation between expenditure drivers, the extent that those correlations appear would already be captured in the examination of historical expenditure. (Attachment B p. 2)</p> <p>Ergon: Some correlations between expenditure drivers exist. However, these are already captured in the examination of historical expenditure. Further identification of correlation between drivers would be subjective and likely to result in errors due to inconsistency. (p. 14)</p> <p>Jemena: This question cannot be answered without first collecting data for each driver and testing for correlations empirically. (p. 11)</p> <p>SP AusNet: Does not expect the expenditure drivers to be strongly correlated with one another. (p. 24)</p> <p>Aurora: Some are uncorrelated e.g. customer requests, while others are correlated, e.g. weather, asset condition and vegetation effects. Consolidating drivers is undesirable. (p. 17)</p> <p>UED: Notes that there are likely to be some (negative) correlations between some of those drivers. For example, increased</p>

vegetation management costs should, in part, reduce the impact of weather events. (p. 14)

MEU: There is a risk in commencing this process too small. The list of drivers should be kept as wide as possible and consolidated if there is a high level of correlation. (p. 32)

Grid Australia: Provided a list of categories indicative of the general categorisation by TNSPs. Described what is included under each category and the drivers that affect these categories. (pp. 28–32)

Question 47

Do you think that the network segments outlined above provide a useful demarcation of the costs of customer-initiated network extension and/or augmentation? Do you think that there are significant cost differences in installing connection point assets and in network extensions between overhead and underground assets? What alternative asset type demarcations would be more appropriate?

Energy Networks Association

Ergon Energy

Jemena

Major Energy Users Inc.

Aurora Energy

ENA: The approach to customer driven capital expenditure proposed in the guidelines assumes a level of detail and network homogeneity that from a practical level is inconsistent with existing business processes and operationally difficult to achieve. The AER needs to acknowledge the level of detail collated for customer driven expenditure varies significantly between DNSPs. (Attachment B, p. 2)

Ergon: Typically, DNSPs categorise connections by purpose, size and location, and the combination of these factors can represent significant differences in cost. Concerned the proposed demarcation assumes a level of detail that is inconsistent with existing business processes, operationally difficult to achieve and would represent a significant burden for all DNSPs. (p. 14)

Jemena: While, conceptually, the network segments outlined make sense, it is difficult to obtain separate data on each segment that is sufficiently robust for intercompany comparisons. Much depends on the work practices in the field, as many of these works will be carried out together and not necessarily recorded separately by segment. (p. 11)

MEU: Yes. There is a clear difference in cost between overhead and underground connections. (p. 32)

Aurora: The segments appear adequate for the task as they reflect those used in Aurora's current determination. Unsure whether they would be suitable for other NSPs. Expenditure should be subcategorised in the same way as in the repx model. There are significant cost differences between underground and overhead assets. (p. 17)

Question 48

Do you agree with separating customer-requested expenditure by connection point assets, extensions, and augmentations? Do you think total expenditure for each service (excluding new connections services) is a sufficient degree of disaggregation? Should further sub-categories be identified?

Energy Networks Association

Ergon Energy

Jemena

Aurora Energy

ENA: As noted in response to Question 47, connection work is typically categorised by connection type not by basic connection, extension and capacity upgrades. In many cases a connection may involve all three components included in a single job making separation of individual components impossible. (Attachment B, p. 3)

Ergon: Reiterates the potential difficulties in applying such categories, when connection work is often classified by type (i.e. residential, business, rural, urban) and these categories are often applied differently by each DNSP, as such, careful consideration and consultation would be required. (p. 14)

Jemena: No. Disaggregation even at this high level would likely be hard to compare between businesses without harmonising recording practices in the field for all businesses. Further disaggregation would be even more problematic. (p. 11)

Aurora: For completeness, customer requested expenditure should be split into the three categorised mentioned but also subcategorised as per those in the repx model. (p. 18)

Question 49

Energy Networks Association

ENA: See response to question 47 and 48. The increase in generation connections may lead to the need for a separate category to capture expenditure driven by the connection of distributed generation. Further consideration is necessary over

<p>Do you agree with separating new customer connections expenditure by the connection point, extension, and augmentation components? Do you think that the number of new connections, length of network extensions added, and size of capacity added are useful measures of the volume of work and expenditure required for new connection services? Should these categories be disaggregated into more detailed categories reflecting the type of work undertaken by the NSP to account for factors that drive changes in new connections expenditure over time?</p>	<p>Jemena Aurora Energy</p>	<p>how length and capacity of mains are considered. For example, MVA-km may provide a better measure than just MVA or just length. (Attachment B, p. 3)</p> <p>Jemena: These measures are useful, but JEN is not in a position to comment whether these are the optimal measures to use. (p. 12)</p> <p>Aurora: The number of new connections, length of extensions, and size of capacity added are useful volume and expenditure measures. (p. 18)</p>
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Question 50

Do you think the system growth expenditure driver category should be distinguished by expenditure directed at addressing different service standard issues, such as harmonics, voltage variance, ferro-resonance, and system fault levels? Would the benefits of distinguishing expenditure into these sub-categories for forecasting the timing and scope of changes in expenditure trends over time outweigh the added complexities from doing so?

<p>Energy Networks Association</p>	<p>ENA: A separate categorisation of expenditure to address harmonics, fault levels and voltage compliance can be potentially meaningful, given its significance. However, further examination is required to determine if the effort of collecting the required data is matched by the benefit. The augex model currently does not capture expenditure to comply with service standards or changes in Codes, which are major drivers of augex. (Attachment B, pp. 3–4)</p>
<p>Ergon Energy</p>	<p>Ergon: It is important to distinguish sub-categories of system growth for operational purposes. This is reflective of a normal power engineering approach, as system growth expenditure is driven by numerous factors. (p. 15)</p>
<p>Major Energy Users Inc.</p>	<p>MEU: Probably Yes. The approach should start by being comprehensive but which can be reduced at a later time is seen as evidence shows that the effort is not worth the benefit. (p. 33)</p>
<p>Aurora Energy</p>	<p>Aurora: Not convinced these given subcategories would be beneficial in forecasting the timing and scope of changes in expenditure trends. The measurement of outputs would be challenging given the interactions between solutions. (p. 19)</p>

Question 51

Do you think that the network segments outlined above provide a useful demarcation of the costs of general load driven network

<p>Energy Networks Association</p>	<p>ENA: The segments proposed in section 2.2.2 of the issues paper can be considered reasonable however it should be at the business' discretion to further disaggregate beyond the network segments outlined. If the network segments were mandated then some utilities may encounter problems. (Attachment B, p. 4)</p>
<p>Ergon Energy</p>	<p>Ergon: To be comfortable with the suggested network segments, suggests that the Augex model requires detailed re-engineering to assess the cost of added capacities and ratio of added capacity to demand growth. (p. 15)</p>
<p>Aurora Energy</p>	
<p>United Energy, Multinet (joint</p>	

<p>extension and/or augmentation? What alternative asset type demarcations would be more appropriate?</p>	<p>submission)</p>	<p>Aurora: The given segmentation would be adequate. The categorisation of distribution feeders is unnecessary. The SCNRR feeder classification is unworkable in Tasmania as discussed in the recent reset process. (p. 19)</p> <p>UED: The two primary outputs of the Augex model mentioned on p. 103 of the issues paper, namely 'costs per MVA of added capacity' and 'ratios of capacity added to demand growth' would need careful interpretation before they could be used as even an indicator of the need for further, more detailed, engineering analysis. (p. 14)</p>
<p>Question 52 Do you think the above asset types are sufficient in capturing the cost differences associated with activities to address deterioration in asset condition? What other asset types may be suitable?</p>	<p>Energy Networks Association Ergon Energy Jemena Major Energy Users Inc. Aurora Energy</p>	<p>ENA: Agrees with the list of asset types identified in the issues paper; however, it notes a number of issues to be considered. (Attachment B p. 4)</p> <p>Ergon: Regards the suggested list as an adequate start, but would request recognition of the difference between an asset class (as in RAB and Depreciation Tables) and asset equipment/type which is usually the target of maintenance activities. (p. 15)</p> <p>Jemena: JEN uses a much more granular view of asset types for asset management. However, each distributor uses a different approach to classifying assets. (p. 12)</p> <p>MEU: Probably. However, concerned that some of the costs that are incurred result from poor management and lack of preventative O&M. The measures must ensure that these causes of O&M are properly captured. (p. 34)</p> <p>Aurora: The given categories would be adequate. (p. 19)</p>
<p>Question 53 Do you think cost differences between emergency rectification activities and other activities to address deteriorating asset condition are sufficient to require separate categorisation?</p>	<p>Energy Networks Association Ergon Energy Major Energy Users Inc. Aurora Energy</p>	<p>ENA: There are no synergies between emergency rectification activities and planned activities to address deteriorating asset condition. Therefore, there should be separate categories for these activities for distribution networks. (Attachment B p. 5)</p> <p>Ergon: Ergon does not forecast emergency rectification by asset class or equipment. It would be appropriate for them to require separate categories. (p. 15)</p> <p>MEU: Yes. Emergency rectification is an indicator of poor management and lack of preventative O&M. Measuring this work provides an indication of what is needed and what the trends are. (p. 34)</p> <p>Aurora: Yes. (p. 19)</p>
<p>Question 54 Do you think cost differences between non-emergency prevention activities and non-emergency rectification activities to address deteriorating asset condition are sufficient to require separate categorisation?</p>	<p>Energy Networks Association Ergon Energy Aurora Energy</p>	<p>ENA: Seeks clarification of the categorisation of these activities. It is suggested this question is addressed in further detail during the relevant workshop(s). (Attachment B p. 5)</p> <p>Ergon: Regards this as an area that requires caution, and is related strongly to a DNSP's capitalisation and work management policies. (p. 15)</p> <p>Aurora: Yes. (p. 20)</p>

<p>Question 55</p> <p>Do you think cost differences between non-emergency replacement activities and non-emergency maintenance activities are sufficient to require separate categorisation?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Major Energy Users Inc.</p> <p>Aurora Energy</p>	<p>ENA: Questions the benefit of disaggregating operating expenditure to this level of granularity. Also notes that the AER should give further consideration of the EBSS which provides an incentive for a business to develop the least cost solution. (Attachment B p. 5)</p> <p>Ergon: Unsure there will be benefit in disaggregating operating expenditure to this level of granularity, particularly given the EBSS already provides incentives for a business to develop the least cost solution. (pp. 15–16)</p> <p>MEU: Yes. Combined, this would be a large category and deserving of separation. (p. 35)</p> <p>Aurora: Yes. Also, the activities are sufficiently different to warrant separate classification. (p. 20)</p>
<p>Question 56</p> <p>Do you think the approach to using benchmarking and trend assessment for routine and non-routine maintenance is reasonable? Are there any alternatives which might be more effective?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Jemena</p> <p>Major Energy Users Inc.</p> <p>Aurora Energy</p>	<p>ENA: Questions how adopting a routine maintenance model will provide a more robust forecast for the DNSP. There are a range of uncontrollable factors that will reduce the comparability of routine maintenance expenditure including the age of the asset and the operating environment. (Attachment B p. 5)</p> <p>Ergon: Does not believe a routine maintenance model would be appropriate for deterministic purposes, given the differences in DNSP structures, operating environments and assets. (p. 16)</p> <p>Jemena: Does not believe that a model could substitute active asset monitoring and asset management. It would be more difficult to use such approaches on non-routine maintenance than routine maintenance. (p. 12)</p> <p>MEU: Yes. These must be defined so that the efficient boundaries can be defined and the differences then be measured. (p. 35)</p> <p>Aurora: Benchmarking and trend assessment may be reasonable for routine maintenance, but less so for non-routine due to its ad hoc nature. (p. 20)</p>
<p>Question 57</p> <p>Given the relative predictability of maintenance cycles and activities, do you consider it feasible to construct a deterministic maintenance model, such as that described above?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Jemena</p> <p>Major Energy Users Inc.</p> <p>Aurora Energy</p>	<p>ENA: Disagrees that maintenance cycles and activities are relatively predictable. For instance, non-routine maintenance is heavily dependent on storms and therefore not predictable. (Attachment B p. 6)</p> <p>Ergon: Asserts that a generalised deterministic model developed for application across the industry is unlikely to be successful, as non-routine maintenance will be prompted by different uncontrollable and unpredictable factors for each DNSP. (p. 16)</p> <p>Jemena: No. A model could not substitute active asset monitoring and asset management. If it could, businesses would already be using such models as the main tool for managing their maintenance. (p. 12)</p> <p>MEU: Yes, although experience with using the tool and using the outputs will increase the usefulness. (p. 35)</p> <p>Aurora: It is feasible to attempt to construct a deterministic model for routine maintenance activities. (p. 20)</p>
<p>Question 58</p> <p>Do you think that expenditure directed at altering network infrastructure or management</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Aurora Energy</p>	<p>ENA: The degree of expenditure resulting from change in regulatory obligation will differ between DNSPs. There are challenges in capturing the incremental expenditure due to a change in a regulatory obligation for an existing activity. (Attachment B p. 6)</p> <p>Ergon: The degree of expenditure resulting from change in regulatory obligations will differ between DNSPs. Further, there</p>

systems to ensure compliance with a changed regulatory obligation can be disaggregated in a way that improves accuracy in forecasting and efficiency assessments?

are challenges in capturing incremental expenditure due to a change in regulatory obligation for an existing activity. (p. 16)

Aurora: Agrees that compliance expenditure cannot be disaggregated to improve forecasting/ efficiency assessments. (p. 21)

Question 59

Do you think cost differences between emergency rectification activities and other activities to address third-party actions are sufficient to require separate categorisation?

Energy Networks Association
Ergon Energy
Aurora Energy

ENA: Proposes that vegetation management is not grouped under the heading of 'third party actions'. The ENA also supports the separation of third-party costs as asset relocation requests are quite separate to vandalism and theft, for example. (Attachment B p. 6)

Ergon: Supports the proposal to separate third-party actions and emergency rectification. (p. 16)

Aurora: Yes. (p. 21)

Question 60

Do you think expenditure on managing vegetation growth should be distinguished from expenditure on third-party stochastic events? Should expenditure on third-party stochastic events be distinguished into sub-categories?

Energy Networks Association
Ergon Energy
Jemena
Major Energy Users Inc.
Aurora Energy
Grid Australia

ENA: DNSPs have already been separately reporting vegetation management as the RIN has a separate operating expenditure category for vegetation management. Generally questions the benefit of disaggregating operating expenditure into sub-categories. Disagrees with the assertion that vegetation growth tends to occur at reasonably predictable rates. The EBSS provides an incentive for businesses to develop the least cost solutions. (Attachment B pp. 6-7)

Ergon: Ergon already maintains a register of vegetation information that is disaggregated for its own purposes and can attest to the inaccuracy of the AER's assertion that 'vegetation growth tends to occur at reasonably predictable rates'. In addition to the EBSS incentives to develop the least cost solutions... (p. 16)

Jemena: The AER overestimates the predictability of vegetation growth, which is dependent on weather patterns. (p. 12)

MEU: vegetation management is a significant cost, which is dependent on the environment through which the network operates. Because of the size of the cost, there is value in identifying lengths of line exposed to some sub groups (e.g. urban leafy, forest, open pasture, etc.) and the costs for each benchmarked across all NSPs. (p. 36)

Aurora: Expenditure on managing vegetation growth should be distinguished from expenditure on third-party stochastic events. Expenditure on third-party stochastic events need not be distinguished into sub-categories. (p. 21)

Grid Australia: for transmission – no material cost difference between emergency rectification and third party actions. No separate category for third part actions is warranted. Vegetation management form a distinguishable part of maintenance activities and already has a sub-category within maintenance. (p. 39)

Question 61

Do you think general measures of network size and type are sufficient measures for investigating differences in third party expenditure across service

Energy Networks Association
Ergon Energy
Major Energy Users Inc.

ENA: More relevant measures for third-party expenditure (for discussion) may include geographic location, level of construction activity, level of traffic, seasonal climate of the network area and socio-economic profiles of the network area and the customers. (Attachment B p. 7)

Ergon: Already separates third-party expenditure, and is not convinced that analysis of third-party expenditure on the basis of measurements related to network size and type will be appropriate to produce meaningful information for benchmarking.

providers? What other measures may be useful?		(p. 17) MEU: No. The measure should be reduced into the four basic subgroups (CBD, urban, etc.). (pp. 36–37)
Question 62 Do you think overheads should be separately reported, or included on a fully-distributed basis in the expenditure driver-activity-asset categories, or both?	Energy Networks Association Ergon Energy Jemena Major Energy Users Inc. Aurora Energy United Energy, Multinet (joint submission)	ENA: Overheads should be separately reported and due to the differences between DNSPs they should be assessed and reported at an aggregated level. In general, expenditure categories need to be clearly defined and only contain those costs necessarily incurred in undertaking that work for comparable benchmarking purposes. (Attachment B p. 7) Ergon: Provides a number of unregulated activities, meaning that should overheads be reported as a group, its results would be distorted as against other DNSPs without similar levels of unregulated service activity. (p. 17) Jemena: Overheads should be reported and assessed at an aggregated level, as all businesses will appropriately have different approaches to allocating overheads through to activities and assets. (pp. 12–13) MEU: As a matter of principle, overheads must be separately identified and costed, and a common basis developed for their identification. The greater the aggregation of overhead costs, the greater the ability to argue the need for higher allowances than the benchmark. (p. 37) Aurora: Overhead expenditure need only be separately reported; fully distributed cost reporting is a function of the CAM which is not being assessed. (p. 22) UED: Overheads should be separately reported and due to the differences between DNSPs they should be assessed and reported at an aggregated level. (p. 15)
Question 63 How do you think overhead expenditure should be distinguished and assessed? How would you define any overhead expenditure sub-categories?	Energy Networks Association Ergon Energy Jemena Major Energy Users Inc.	ENA: Overhead expenditure for preliminary purposes can be defined as that which is not related to the management and operation of network infrastructure. (Attachment B p. 8) Ergon: For the purposes of benchmarking, Ergon Energy suggests the least complex approach may be to use direct costs only when seeking to identify the variables that make each DNSP different. (p. 17) Jemena: Overheads should be assessed at an aggregate level and the assessment should always look at both overheads and direct costs holistically. (p. 13) MEU: The issues paper (p. 111) provides what appears to be an acceptable separation of activities. However, what is critical is that the same basis is used for all NSPs so that the overhead costs can be compared, and that there is no variation in the other costs being benchmarked. (pp. 37–38)
Category analysis questions—Other issues in category based assessment		
Question 64 How material do you think are changes in input prices on overall expenditure levels? What forecasting and modelling	Energy Networks Association Ergon Energy SP AusNet	ENA: The changes in input prices are material and due to the majority of the inputs being specific to the network businesses, they can diverge significantly from the input prices of other industries. (Attachment B, p. 9) Ergon: Changes in input prices on overall expenditure levels are significant. Materials are often purchased on the basis of large, long-term contracts, and due to the specialised nature of the equipment, are exposed to currency and other fluctuations that will not necessarily align with local economic drivers. Agrees with the suggestion of incorporating

<p>approaches do you think can reliably account for the impact of input price changes on expenditure without introducing overly burdensome reporting requirements?</p>		<p>appropriate risk sharing mechanisms such as pass through adjustments to allow for circumstances where factors are particularly uncertain and unmanageable. (p. 17)</p> <p>SP AusNet: Input prices are important factors in a regulatory determination. Changes in the costs of materials and labour are likely to be pro-cyclical as economic growth affects demand and input prices. Exchange rates are subject to significant volatility, which may also affect input prices. Appropriate that these issues are addressed in each price determination, especially as economic conditions have been subject to rapid change in recent years. (p. 24)</p>
<p>Question 65</p> <p>What categorisation of different inputs do you think provides a sufficient understanding of both how input prices may change over time, as well as how input prices may vary across geographical locations?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Jemena</p> <p>SP AusNet</p>	<p>ENA: Agrees that the categories of inputs outlined in Attachment B section 3.1 of the issues paper, can materially influence the cost of inputs. However, the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used. Consequently, the price of manufactured network materials may not be well correlated with raw material costs. (Attachment B, p. 9)</p> <p>Ergon: Requests that the AER consider the difficulty in changing the input mix, particular on a short term basis, and note that it would not be prudent for a DNSP to seek to change their mix unless there was a high degree of confidence that the change in relative prices would be sustained. Either way, the potential for forecasting error exists. (p. 17)</p> <p>Jemena: Since past price changes are not indicative of future price changes, does not see how collecting historical information on input prices would be beneficial. It is important that, when dealing with any particular input, the AER uses a forecasting method that is fit for purpose. For example – for some inputs, commodities futures prices can be used, for others consensus expert forecasts may be the best option available, while in some cases the AER may need to start with a commodity future price and adjust for value-added activities that are required to produce the input from the commodity. (p. 13)</p> <p>SP AusNet: The AER's current approach to these issues is appropriate. (p. 25)</p>
<p>Question 66</p> <p>Do you consider optimism bias and/or strategic misrepresentation to be a material issue in the cost estimation for non-routine projects? Do you consider downward biases in cost estimation to materially outweigh regulatory incentives to over-estimate expenditure? To what extent do you consider there to be a consistent downwards bias in initial project cost estimates?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Jemena</p>	<p>ENA: Each DNSP applies varying techniques to build up specific project budgets. It needs to be recognised that when the estimates are being prepared for regulatory proposals there will be unidentifiable costs due to the high level nature of the scopes. (p. 9)</p> <p>Ergon: Generally, strategic misrepresentation is not an issue under the current NER regime. Each DNSP applies varying techniques to build up specific project budgets. (p. 17)</p> <p>Jemena: Does not consider strategic misrepresentation to be an issue under the current NER regime. Strategic misrepresentation would require a company officer to make a false statutory declaration to the AER, which is highly unlikely, given the personal and professional implications of such conduct. (p. 13)</p>
<p>Question 67</p> <p>What should be our approach to</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p>	<p>ENA: Does not advocate the prescription of a particular methodology to take into account these risks as this will depend on the cost estimating methodology used by a DNSP. In general, supports strong incentive schemes to drive efficient levels of expenditure, which would then be taken into account in determining expenditure forecasts. This removes the AER's concern</p>

cost estimation risk factors and addressing potential asymmetric estimation risk? Would techniques such as reference class forecasting be beneficial? How would any techniques to address asymmetric cost estimation risk interact with potential incentive schemes (for either opex or capex)?

that forecasts would be inflated by the use of risk factors developed from past actual expenditures which were not efficient. (pp. 9–10)

Ergon: Emphasises that forecast capital expenditures are made on the basis of estimates for projects, many of which are only in concept phase. Understandably, there are risks associated with achieving accurate forecasts where so many of the elements are either subject to change or yet to be identified. (p. 18)

Question 68

Do you think our established approach to assessing debt and equity raising costs remains appropriate? What modifications or alternative techniques would you suggest?

Energy Networks Association

Ergon Energy

Jemena

Major Energy Users Inc.

SP AusNet

ENA: The approach to estimating equity-raising costs by modelling benchmark cash flows is appropriate. However, the AER has used subtly different models in various determinations to determine equity raising costs and some parties have had specific concerns with the AER's calculations. (p. 10)

Ergon: It is an open question whether pre-issuance debt costs should be treated as opex or a part of the benchmark return on debt allowance. Pre-issuance debt costs are a valid cost which should be recovered. (p. 18)

Jemena: This issue should be addressed in the development of the cost of capital guidelines, due to the important interlinkages with estimating the cost of capital. (p. 14)

MEU: No. The allowance for debt and equity acquisition should be built up from the revealed costs of the NSP and these costs applied to the amount of new funds required. (p. 41)

SP AusNet: It is appropriate that this issue be dealt with through the AER's WACC guideline review. (p. 25)

Question 69

Do stakeholders have any in-principle views on how demand forecasts should be derived and assessed?

Energy Networks Association

Ergon Energy

Jemena

Major Energy Users Inc.

SP AusNet

Aurora Energy

ENA: Comfortable with the approach recommended by the AER provided clear definitions such as a suitable long time series can be agreed with the AER. Consideration should be given to the treatment of additional factors such as the treatment of embedded generation including solar PV. (Attachment B, p. 10)

Ergon: Comfortable, in-principle, with the AER's recommended approach. For demand to be meaningful for capex, it needs to be analysed at a localised level. (p. 18)

Jemena: Approaches used in previous price reviews are sufficiently robust to be maintained. (p. 14)

MEU: Whilst the proposal for assessing increased demands in elements of the networks is a sound approach, also considers that the build up from this approach should be reconciled with the overall expected regional change in demand. (pp. 41–42)

SP AusNet: In relation to transmission, demand forecasts play a very limited role in SP AusNet's revenue determinations, as augmentations to the shared network are a matter for AEMO. (p. 25)

Aurora: The approach in the Issues Paper is reasonable. Temperature correction should only be applied to historical data if it is a forecasting input. (p. 23)

<p>Question 70</p> <p>Do you think that the network segments outlined above provide a useful demarcation of the expenditure incurred to address various expenditure drivers? Do you think that there are significant cost differences in building, repairing, or replacing network assets based on region in which the work is being done? What alternative asset type demarcations would be more appropriate?</p>	<p>Energy Networks Association Ergon Energy Aurora Energy</p>	<p>ENA: Whilst there can be significant cost differences in building, repairing or replacing network assets depending on the region, this question cannot be answered without substantial empirical analysis. (Attachment B, p. 11)</p> <p>Ergon: Suggests that further detailed empirical analysis is undertaken before this question can be definitively answered. (p. 18)</p> <p>Aurora: The feeder categories (CBD, urban etc.) are not relevant for Tasmania. The costs of building, repairing and replacing assets are not significantly different between areas in Tasmania. Unconvinced there is a need for feeder demarcation, however by feeder voltage may be more useful if demarcation is required.(p. 24)</p>
<p>Question 71</p> <p>For the purposes of comparative analysis of various expenditure categories, do have any views on how to best control for difference in approaches to cost allocation, capitalisation and outsourcing?</p>	<p>ActewAGL Energy Networks Association Ergon Energy Jemena Major Energy Users Inc. SP AusNet</p>	<p>ActewAGL: Strongly disagrees with the AER's proposal to employ a CAM that is neutral to indirect cost allocation and requires NSPs to allocate call costs to various drivers. (p. 3)</p> <p>ENA: In determining an appropriate CAM, consideration needs to be given to the reality that most businesses allocate their costs according to their CAM, through the same business finance systems that are used to produce statutory accounts. (p. 11)</p> <p>Ergon: The CAM should not be developed in isolation from the fact that most businesses allocate costs through the same finance systems that are used to produce statutory accounts and therefore the cost/administrative burden of amending the CAM would need to be considered. (p. 18)</p> <p>Jemena: The best control for these issues is ensuring that costs are not disaggregated to an unnecessarily low level. The AER should benchmark disaggregated direct costs (where cost allocation plays a lesser role) and aggregated overheads (prior to them being allocated down to various cost categories). (p. 14)</p> <p>MEU: There has to be a single approach to capitalisation used when benchmarking performance. If different capitalisation approaches are allowed, the benchmarks will be different and therefore less useful. (p. 42)</p> <p>SP AusNet: It is more difficult to control for these differences if the analysis is highly disaggregated. The AER's analytical approach should recognise that benchmarking analysis is inherently difficult partly because companies legitimately adopt different approaches to cost allocation, capitalisation and outsourcing. (p. 26)</p>
<p>Question 72</p> <p>Do you think our conceptual framework for the assessment of related party contracts is reasonable? What other techniques</p>	<p>Energy Networks Association Ergon Energy Jemena SP AusNet</p>	<p>ENA: The framework treats the related-party contractor as a regulated entity, rather than recognising that the contractor participates in a competitive market. The key concept should be whether the costs incurred by the regulated utility (and ultimately by customers) are higher or lower than those that would be incurred if an unrelated party contractor was used. (p. 11)</p> <p>Ergon: Approach to related-party contracts and margins (and the overall framework) needs to be transparent and well</p>

<p>may be appropriate? Should we apply the same conceptual framework when assessing the efficiency of related party margins on an ex post basis?</p>		<p>understood, allowing business to have a full understanding of how each transaction will be assessed. (p. 18)</p> <p>Jemena: Does not agree with the AER's conceptual framework, which has yet to be tested through review by the Australian Competition Tribunal. The AER's framework treats the related-party contractor as though it is itself a regulated entity, rather than recognising that the contractor participates in a competitive market. (p. 14)</p> <p>SP AusNet: The AER's conceptual framework is well understood. Agrees with the AER's observation that benchmarking of particular cost categories may provide assistance in assessing margins included in related-party contracts. (p. 26)</p>
<p>Question 73</p> <p>Do you think our conceptual framework for assessing self-insurance is appropriate? What other techniques may be appropriate?</p>	<p>Energy Networks Association</p> <p>Ergon Energy</p> <p>Major Energy Users Inc.</p> <p>SP AusNet</p>	<p>ENA: Self-insurance is an appropriate mechanism for the management of risks particularly with respect to:</p> <ul style="list-style-type: none"> ▪ uninsurable risks (either as no insurance is available or insurance is not available on economic terms) ▪ the amount of the deductibles under insurance policies ▪ historical claims or self-insured losses including frequency, severity and likelihood versus the cost of the policy ▪ any amount above insurance policy limits ▪ other uninsured risks businesses consider it appropriate to retain. <p>These costs are all 'business retained costs' therefore it is important not to too narrowly define self-insurance costs as catastrophic events that occur only rarely. (Attachment B pp. 11–12)</p> <p>Ergon: As per ENA response (p. 19).</p> <p>MEU: Although the AER approach addresses many concerns, it does not identify the need to assess the claims history of the NSP and benchmark this against what is more generally seen in the industry. Also, the AER needs to analyse the opex and capex actually used (compared to external benchmarks) to identify any trends as to whether there is correlation between actual opex and capex, claims history and the insurance costs. (p. 44)</p> <p>SP AusNet: The current conceptual framework for assessing self-insurance is appropriate. (p. 26)</p>
<p>Question 74</p> <p>Do stakeholders have any in principle views on how benchmarks should be derived and applied?</p>	<p>Ergon Energy</p> <p>Major Energy Users Inc.</p> <p>SP AusNet</p>	<p>Ergon: Reiterates its position that benchmarks are a tool for guidance, which cannot and should not be used as a 'black-box' for determining expenditure allowances. When benchmarks are used, inevitably there is intense debate which often overshadows any benefits that could be taken by DNSPs to modify aspects of their service delivery. (p. 18)</p> <p>MEU: The benchmarking exercise needs to address more focused benchmarks, especially where these increase the amount of comparative data. Such a benchmark might then be hours of maintenance/urban substation/MW capacity, or capex/residential customer/short rural. Disaggregation of benchmarks is an essential step in the process of ensuring the efficient frontier has been reached. (p. 45)</p> <p>SP AusNet: Supports the AER's proposed holistic approach, which should facilitate a consideration of all available economic benchmarking techniques. (p. 26)</p>

Table C.2 Submissions received by CRG subgroup

Summary of issue raised at CRG or CRG subgroup meetings	AER response
Consumers would prefer one benchmark firm.	The benchmark will be measured relative to a revealed frontier having consideration for the circumstances of the firm in question. This will depend on the robustness of the analysis. We propose to include all NSPs in our benchmarking analysis.
Consumers are concerned that expenditure forecasts are driven by high service standards.	The AEMC is currently considering a rule change to the expenditure objectives in the National Electricity Rules to address the possibility consumers are paying for services above the level they value in some circumstances. The change would result in NSPs only being able to claim expenditure for quality, reliability and security in their proposals sufficient to comply with jurisdictional standards. This is discussed in section 3.2 of the explanatory statement. We also note the guidelines do not discuss efficient service standards as we do not set the standards.
Benchmarking relies on NSPs to provide data, so they still have an incentive to overinflate. The AER needs to be conscious of this.	Reviewing the data and assumptions of NSPs is an inherent part of the expenditure review process. Benchmarking data will be collected using legal instruments.
The businesses may try to hide behind confidentiality concerns. If there are confidentiality concerns, then the AER should have a process for dealing with the information.	Section 2 of the Confidentiality Guidelines indicates that we consider that all stakeholders should have access to sufficient information to enable them to understand and access the substance of all issues affecting their interests. These guidelines attempt to strike a balance between ensuring adequate disclosure of information, while complying with our obligations under the National Electricity Law and Competition and Consumer Act 2010.
Not all businesses are the same. Differences include urban/rural, customer and energy density, climate factors. The AER needs to consider which differences is material.	We will collect data on operating environment factors when undertaking our benchmarking analysis. We will consider the materiality of these factors in making our determinations.
Businesses may argue that revealed costs are not a good indicator of what costs should be going forward. They may argue that costs will be different going forward.	Our preferred opex forecasting approach is to use revealed costs, subject to an efficiency assessment. This is discussed in section 4.2 of the explanatory statement.
Consumers would like to see a complete set of data, both raw data and data that has been analysed and interpreted.	Section 6 of the guidelines set out the data that must be provided to support regulatory proposals. This is covered in further detail in Appendix B of the explanatory statement. Subject to genuine claims of confidentiality, we currently intend to publish as much raw and analysed data as possible.
Consumers would favour the AER consider using benchmarks as a forecast, that is, in considering whether proposals for expenditure are acceptable.	We intend to apply benchmarking in conjunction with other expenditure assessment techniques to review forecasts. We will not preclude using benchmarking to determine expenditure allowances. If, on the balance of evidence (accounting for submissions), we consider benchmarking provides the most appropriate forecast, then we will use it to set expenditure allowances. At this stage, it is too early to form a view on the appropriate weight to apply to assessment techniques.
AER should recognise weakness in the current regime assuming symmetrical risk. Where they can include it into RAB if overspend, and if they underspend it doesn't get clawed back as it is under the allowance.	This issue is addressed in the design of the capital expenditure incentive arrangements. This is considered in the explanatory statement to the Capital Expenditure Sharing Scheme.
Where expenditure decisions are being made it would	We will report NSPs' actual expenditure in our annual performance

be helpful to know why it is being spent and when it is being spent. As an example, is expenditure occurring in the last year in particular?

and benchmarking reports.

Consumers would like up-to-date capex. For example, if expectations of demand were wrong, then consumers would like to know what capex is being spent.

We will report NSPs' actual expenditure and actual demand in our annual performance and benchmarking reports.
