Networks NSW – AER draft determination

Ashurst Australia

16 January 2015

Expert report

FINAL

Confidential

Prepared by:

Cambridge Economic Policy Associates Ltd

CONTENTS

1. Introduction **1**

1.1. My experience and expertise 1

1.2. Background 2

1.3. Instructions 3

2. General observations on the regulatory framework and its objective **5**

3. Specific observations on the regulatory framework and its objective in the context of the achievement of efficiencies **22**

4. Declaration **34**

ANNEX A Econometric results **35**

ANNEX B Curriculum Vitae **37**

ANNEX C Letter of instructions **44**

ANNEX D Amendment to letter of instructions **59**

ANNEX E Documents I have been instructed to consider **63**

1. INTRODUCTION

I have been engaged by Ashurst, on behalf of Networks NSW, for the purposes of the Response, to, *inter alia*:

(a) provide economic analysis and advice; and

(b) prepare a written expert report (or reports).

The letter of instruction is included as an Appendix. For Ease of reference I have included the full list of questions I have been asked to consider in section 1.3.

1.1. My experience and expertise

I am CEPA's Chairman. I am a Research Fellow in the Control and Power Research Group at Imperial College London and Emeritus Professor of Applied Economics at the University of Cambridge, where I was Director of the Department of Applied Economics from 1988 - 2003. I am Research Director of the Electricity Policy Research Group at the University of Cambridge, a multi-disciplinary research group supported by public funding from various Research Councils and support from stakeholders in industry and regulatory agencies. I was the 2013 President of the International Association for Energy Economics. I spent two years as a Division Chief in the World Bank and have been a visiting Professor at Berkeley, Princeton, Stanford and Yale. I am a fellow of both the Econometric Society and the British Academy. I am the Deputy Independent Member of the Single Electricity Market of the island of Ireland, and was Chairman of the Dutch Electricity Market Surveillance Committee from 2001-5 and a member of the Competition Commission from 1996 to 2002.

I am an internationally recognised expert on economic regulation and reform of network industries and the transport sector. I have led and participated on numerous CEPA assignments in the Economic Regulation and Competition practice area for clients such as the UK's Ofgem (Office of Gas and Electricity Markets), the Portuguese Competition Commission, the Dutch Office of Energy Regulation and other regulatory agencies and regulated companies.

My publications include the book *Privatization, Restructuring and Regulation of Network Utilities* (MIT Press, 2000). I was the guest editor of *The Energy Journal* (2005) issue on European electricity liberalisation, and the recipient of a Festschrift "Papers in Honor of David Newbery: The future of electricity" in *The Energy Journal* (2008).

In preparing this report, I have been assisted principally by two CEPA colleagues, Ian Alexander and Joel Cook. Notwithstanding this assistance, the opinions in this report are my own and I take full responsibility for them.

I have read the Federal Court of Australia's Practice Note CM7, June 2013, which provides guidelines on the preparation of Expert Witness Reports. I understand these guidelines and have complied with the Practice Note.

1.2. Background

The National Electricity Objective (NEO) set out in section 7 of the National Electricity Law reads-:

> *"The objective of this Law is 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."*

Section 16 of the National Electricity Law requires that the AER must, in performing or exercising an AER economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the NEO. The making of a distribution determination is an AER economic regulatory function or power. Further, section 16(1)(d) requires that if the AER is making a distribution determination and there are two or more possible reviewable regulatory decisions that will or are likely to contribute to the achievement of the NEO, the AER is required to make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.

Also of particular relevance are the revenue and pricing principles set out in section 7A of the National Electricity Law. Relevantly, section 16(2)(a) provides that the AER must take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination relating to direct control services.

The revenue and pricing principles are set out in section 7A of the National Electricity Law and provide, amongst other things that: (a) a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services; and complying with a regulatory obligation or requirement or making a regulatory payment; (b) 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; (c) a price or charge for the provision of direct control network services 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; (d) 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 network or a transmission system with which the operator provides direct control network services; and (e) 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.

I am requested that my report should address the following topics *italicised below* in the context of the NEO and the revenue and pricing principles. The answers to these topics are given after listing that topic.

1.3. Instructions

The questions I have been asked to consider are:

General observations on the regulatory framework and its objective

(a) The economic basis and purpose for the regulation of monopoly electricity distributors.

(b) What do you understand the NEO to mean?

(c) What would be the key design features of an economic regulatory regime that is designed to achieve the NEO?

(d) Pursuant to clause 6.4.3 of the NER, the annual revenue requirement for a distribution network service provider for each year of a regulatory control period must be determined using a building block approach, under which the building blocks are:

   (i) indexation of the regulatory asset base;

   (ii) a return on capital for that year;

   (iii) the depreciation for that year;

   (iv) the estimated cost of corporate income tax of the distribution network service provider for that year;

   (v) the revenue increments or decrements (if any) for that year arising from the application of any relevant incentive scheme;

   (vi) the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period;

   (vii) the revenue decrements (if any) for that year arising from the use of assets that provide standard control service to provider certain other services; and

   (viii) the forecast operating expenditure for that year.

In your view, and as a general matter without considering the specific circumstances of a particular network, is a correct application of the building block framework to determining the annual revenue requirement for direct control services likely or not to contribute to the achievement of the NEO? If so, how? If not, why not?

(e) To the extent you consider in response to (d) that the correct application of the building block framework is likely to contribute to the achievement of the NEO, if there is a material error in the application of the framework what are the likely consequences for the achievement of the NEO or the purpose of the economic regulation of monopoly electricity distributors referred to above?

(f) How, if at all, the appropriate regulation of monopoly electricity distributors takes into account the actual position of the regulated entity.

(g) Please comment on the AER's approach to benchmarking.

Specific observations on the regulatory framework and its objective in the context of the achievement of efficiencies

(a) To the extent costs are forecast to be incurred in a regulatory control period (such as redundancy payments) which are associated with the restructuring of a business undertaken to reduce costs in the long-run, what considerations are relevant to the regulatory treatment of such costs, including in the context of a regime that has as its objective one such as the NEO?

(b) Review and comment on Attachment 7 to the draft determination.

2. GENERAL OBSERVATIONS ON THE REGULATORY FRAMEWORK AND ITS OBJECTIVE

(a) *The economic basis and purpose for the regulation of monopoly electricity distributors.*

Regulation of potentially profitable network monopolies such as electricity distributors is required to serve the long term interests of consumers (in this case of electricity). At its most fundamental, consumers of essential services that are connected to a network monopoly supplier are potentially at risk of exploitation by that monopoly supplier, as the meaning of "essential" implies that there are no readily available or comparably cheap substitutes for the service, while a network monopolist has sole economic means of access to the consumer, meaning that alternative suppliers face excessive costs in providing a substitute service.

Without regulation, consumers would likely face excessive prices and/or inferior quality and reliability of service, and would likely use the political process to impose potentially expropriatory redress. Investors in such networks face the risk that once they have sunk their capital in durable networks, it would become politically attractive to hold down prices closer to the variable operating cost, either directly or by failing to allow prices to rise in line with the general price or cost level, and as such their return to the original investment would be expropriated. Fearing that, investors would be loath to sink their capital, and would thus precipitate an inferior quality and reliability of service.

Regulation is thus designed to protect current consumers against excessive prices and/or inferior quality and reliability of service, and to ensure that efficient operators have confidence that they will be allowed to earn a rate of return sufficient to justify investment, such that these network operators will be willing to invest and operate the network to deliver adequate, safe, reliable and secure services now and in the future, to the long-term benefit of consumers.

(b) *What do you understand the NEO to mean?*

The objective of the National Electricity Market (NEM) is set out in section 7 of the National Electricity Law as the National Electricity Objective (NEO) and is repeated here:

> **7—National electricity objective**
>
> The objective of this Law is 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.

Several aspects of this succinct summary are worth remarking in the context of the general principles of energy policy, which have become increasingly salient in a number of jurisdictions, and specifically in the UK and the EU. They are captured in the classic energy trilemma of efficiency, affordability and sustainability. Of these three aspects, the NEO identifies the first two but is silent on the third. Thus the NEO emphasizes efficiency (in operation and investment) and clarifies the definition of the service to be supplied as safe, reliable, of adequate quality and secure, not just to the consumers supplied by any network operator, but also the rest of the national electricity system.

Second, it clarifies affordability as an efficient price, set out in detail as the set of prices (tariffs) that would allow an efficient operator to cover its operating costs, finance the efficient value of past investments, and finance efficient new investments at least cost.

The NEO is silent of the third side of the trilemma triangle, sustainability. One logical interpretation is that regulation should be tightly circumscribed to delivering the right services efficiently to current and future consumers at least cost to those consumers, and other objectives should be pursued by other branches of the state using appropriate instruments, such as taxes, charges, prices (e.g. as for emission allowances under cap-and-trade schemes such as those for SO_2 in the US or for CO_2 under the EU Emissions Trading Scheme), standards or other regulations. That has the advantage of clarity, of encouraging the alignment of instruments with targets, and in this case, simplifies the interpretation of the NEO. This is confirmed by repeated references to efficiency, e.g. in *AER Draft decision Ausgrid distribution determination 2014–19 Attachment 7* (hereafter *Attachment 7*) at p7-40, which states

> *... the NEO, which, as we explain in the explanatory statement to our Guideline, is fundamentally an efficiency objective. The second reading speech introducing the NEL states, for example:*
>
> > 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.

In essence, this explains that service providers are economically efficient when they deliver electricity services to a level in the long run interests of consumers at the lowest sustainable cost having regard to all the factors in the NEO.

For future reference, note that this quote specifically refers to the need for innovation in response to consumer needs. Motivating innovation is problematic for the regulation of utilities, as discussed below when considering Ofgem's recent change in its approach to incentive regulation. To conclude, other externally specified objectives such as environmental sustainability, to the extent that they are legitimate, impose constraints that must be met, and costs that have to be borne, by efficient operators, and which will therefore have to be recovered through the allowed revenue.

(c) ***What would be the key design features of an economic regulatory regime that is designed to achieve the NEO?***

The key features of an economic regulatory regime that is designed to achieve the NEO are that it provides incentives to deliver the objectives of the NEO as set out in (b) above, and which can be summarized as the need to deliver productive, allocative and dynamic efficiency. Of these three, dynamic efficiency, that is to invest and innovate efficiently, is the hardest to incentivize, as the results may only be observable with a long lag, and where it is particularly difficult to disentangle the impacts of skill and uncertainty on the outcomes.

Regulation can be best considered as a Principal-Agent problem[1] in which the regulator as principal has to design an incentive scheme for the agent, the utility, in the presence of asymmetric information, in which the agent is better informed about its options than the principal and where the agent's objectives (e.g. its shareholders' profits or its workers' income) are in conflict with those of the principal (where the principal also has to represent consumer interests). The main lesson from that literature is that there is a trade-off between providing incentives for cost reduction and efficiency and transferring those gains to consumers. High-powered incentives for efficiency in the presence of asymmetric information, in which the principal is unable to distinguish between luck and judgment, transfer reward but also risk to the agent, who must be compensated with a higher return on its investments than in regulatory systems with lower-powered incentives, where risks are more borne by consumers at the expense of less efficient and thus potentially more costly outcomes. The balance depends on the relative importance of the cost of capital and the benefits of efficiency. In capital-intensive utilities like DNSPs and transmission companies, a small increase in the Weighted Average Cost of Capital (WACC) when

---

[1] Newbery, D.M. (2000), *Privatization, Restructuring and Regulation of Network Utilities*, MIT Press; Laffont, J-J. and J. Tirole, (1993) *A Theory of Incentives in Procurement and Regulation*, Cambridge: MIT Press

applied to a large Regulatory Asset base (RAB) could easily outweigh a considerable reduction in operating costs (opex), prejudicing the long term interests of consumers. Thus the key to good regulation is securing the right balance of risk and reward to place on the utility.

Incentive regulation can be contrasted with rate-of-return or cost-based regulation, under which the utility proposes a set of rates (tariffs) that with its forecast sales gives a revenue stream that covers its operating costs, and the return on and of its investment, at a rate of return that is sufficient to finance its investment plans and thus to reward investors for the risks they face. Under the system that evolved in the US over a long period of private regulated ownership of utilities, the utility could request a rate hearing if it considered its current rates (tariffs) no longer met that requirement, and the regulator (State Utility Commission) would then examine the proposal, assess whether past investments were "used and useful", prudently undertaken, and if so set a fair rate of return on these assets. The objection to this form of regulation is that it could, and arguably often did, lead to excessively costly investment ("gold-plating") and that as such it provided too weak incentives to invest efficiently. In short, cost-based regulation fails to provide sufficiently powerful incentives for efficiency, in its desire to claw back all cost improvements to consumers and achieve a low WACC by reducing almost all risk.

In response to such criticisms, when the UK embarked on utility privatization, it chose a form of incentive regulation known as price-cap regulation, in which the regulator would set a price cap for a weighted basket of services provided, indexed to the price level (the Retail Price Index or RPI) but decremented each year by an efficiency or X factor, hence RPI-X regulation. For capital-intensive network industries like electricity, a major part of the cost base is the return on and of the RAB, and the methods of determining the WACC and uprating the RAB are very similar to those in the National Electricity Law, and specifically follow a building block approach.

While this form of price-cap regulation provides strong incentives for the utility to reduce costs, as it retains as profits any cost savings above the X factor (at least until the next periodic price review), without close monitoring of quality of service, there would be an incentive to compromise on quality in order to cut costs. Incentive regulation therefore needs incentives for improving quality (and/or penalties for reductions in quality below a specified level). The most obvious of these for electricity distribution is a payment to consumers for interruptions to supply, and/or penalties for failure to meet the carefully set out Quality of Service Standards (for voltage, frequency, etc.).

In its extreme form, the price-cap would be set for ever, providing the strongest possible incentives but failing to claw back any resulting over-achievement to consumers. The compromise solution is a periodic price review in which the price level, P_0, and the rate of improvement, X, can be reset if necessary. The longer the price control period, the stronger the incentive for cost reduction, so again there is a choice to be made balancing risk and reward.

After 20 years of such regulation, Ofgem, the GB electricity regulator, undertook a review of the success of this system of incentive regulation (RPI-X @ 20),[2] which in turn led to the new regulatory framework of RIIO (standing for Revenue using Incentives to deliver Innovation and Outputs), set out in the RPI-X@20 Decision Document.[3] To quote from that document:

> The RIIO model has taken the elements of the old RPI-X framework that work well, adapted other elements to ensure they are focused on delivery of a sustainable energy sector and long-term value for money, and added elements to encourage the radical measures needed in innovation and timely delivery. The model is designed to promote smarter gas and electricity networks for a low carbon future." (*Handbook for implementing the RIIO model*).

Some, but not all of these objectives align with the NEO, particularly "long-term value for money" and with a view to the longer term, "to encourage the radical measures needed in innovation and timely delivery." It is interesting to note that Ofgem defends the sustainability objective thus:

> 1.8. The two parts of this objective are complementary. Indeed, provision of long-term value for money is a core part of delivery of a sustainable energy sector. … We are focusing on total costs of delivering outputs, wanting network companies to make choices between infrastructure (capital) solutions and non-capital solutions on the basis of which is least cost over the long term. The relevant time horizon will vary by the activity being considered; for some costs 'long term' may be within the eight-year price control period whilst for others it will span a number of price control periods. We expect network companies to focus on the life-cycles of assets and to have asset management plans consistent with the long-term nature of network assets. When considering costs we expect network companies to consider the impact on the environment ('environmental costs'), for example taking account of the price of carbon, when comparing the 'cost' of different options for delivering output.

Some of the more notable departures from the previous RPI-X system are the move from a five-year regulatory period to an eight-year horizon, to allow companies more time to enjoy the fruits of their cost reduction, the emphasis on total expenditure (totex) to improve trade-offs between capital (capex) and operating expenditure (opex), and a shift to longer depreciation periods for the more durable assets. Innovation is stimulated by various funds that can be competitively bid for (LCNF and

---

2 See https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/background-%E2%80%93-rpi-x20-review

3 At https://www.ofgem.gov.uk/ofgem-publications/51870/decision-doc.pdf. Details of how the RIIO model would work in practice are set out in the *Handbook for implementing the RIIO model* at https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbook.pdf

Electricity NIC) and which trial new methods for lowering costs to meet the low carbon objective, and which, if successful, will be used to benchmark what other companies are expected to achieve in the form of smarter grids and management to avoid costly investment.[4]

While the NEO as spelled out in the *Guidelines* refers to the desirability of innovation, it does not specify how this will be motivated. The classic problem facing a utility considering a potentially innovative way of reducing costs is regulatory uncertainty. If the innovation succeeds and reduces costs, then the next price control will claw these gains back, while if it is unsuccessful, its costs may rise, making it appear inefficient, and it will be unable to recover these costs.

(d) ***Pursuant to clause 6.4.3 of the NER, the annual revenue requirement for a distribution network service provider for each year of a regulatory control period must be determined using a building block approach, under which the building blocks are:***

(i) indexation of the regulatory asset base;

(ii) a return on capital for that year;

(iii) the depreciation for that year;

(iv) the estimated cost of corporate income tax of the distribution network service provider for that year;

(v) the revenue increments or decrements (if any) for that year arising from the application of any relevant incentive scheme;

(vi) the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period;

(vii) the revenue decrements (if any) for that year arising from the use of assets that provide standard control service to provide certain other services; and

(viii) the forecast operating expenditure for that year.

In your view, and as a general matter without considering the specific circumstances of a particular network, is a correct application of the building block framework to determining the annual revenue requirement for direct control services likely or not to contribute to the achievement of the NEO? If so, how? If not, why not?

[4] Other jurisdictions and sectors have undertaken similar reviews of the appropriateness of their regulatory regimes. In Australia, IPART reviewed its approaches against other Australian regulators and international best practice - http://www.ipart.nsw.gov.au/Home/Industries/Research/Reviews_All/Incentive_Based_Regulation/Review_of_IPARTs_approach_to_incentive_based_regulation - while in America the regulatory commission in New York has recently commenced such a review - http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument.

In my view, a correct application of the building block framework is the best method currently available for motivating NSPs to deliver the NEO. I defend my assertion in two parts. First, I comment on the way the building blocks are defined in the NER and their relation to delivering the NEO. Second, I refer to good regulatory practice as it has evolved in other jurisdictions, whether that practice would achieve the NEO, and if so whether the AER is following best practice.

The three most important elements in the building block approach are the determination of the allowed investment (capex), of the allowed opex, and "the return on capital for that year", i.e. the WACC. The NER sets out how these elements are to be determined. On capex, the NER at 6.4A (a) states that

… the only capital expenditure that is included in an adjustment that increases the value of that regulatory asset base is capital expenditure that reasonably reflects the *capital expenditure criteria*.

The *capital expenditure criteria* are set out at NER 6.5.7 in (c):

> (c) The *AER* must accept the forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast capital expenditure for the *regulatory control period* reasonably reflects each of the following (the *capital expenditure criteria*):
>
> (1) the efficient costs of achieving the *capital expenditure objectives*;
>
> (2) the costs that a prudent operator would require to achieve the *capital expenditure objectives*; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the *capital expenditure objectives*.

A similar format is set out for opex at 6.5.6 in (c):

> (c) The *AER* must accept the forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast operating expenditure for the *regulatory control period* reasonably reflects each of the following (the *operating expenditure criteria*):
>
> (1) the efficient costs of achieving the *operating expenditure objectives*; and
>
> (2) the costs that a prudent operator would require to achieve the *operating expenditure objectives*; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.

Thus, begging for the moment how one can determine the efficient cost of the required capex and opex, if the DNSP correctly determines these elements of the building block approach, then its proposed expenditures should meet the NEO. I note in particular that both criteria specifically refer to the costs that a prudent operator would require to achieve the objectives, and these would certainly include the costs of meeting any legal obligations, but go beyond that. Prudence is essentially a forward looking concept, in that it may be prudent to take various actions to mitigate the harm that follows some uncertain future event (e.g. a bush fire or cyclone), which after the event (no bush fire, no cyclone) may not have been needed. This is an important proviso for it limits the freedom the AER has in judging outcomes by reference to a benchmarked least cost DNSP that may have been imprudent in not undertaking various activities that turned out, by good luck, not to have been necessary (during that period).

When comparing the building block approach with international good practice, I noted in the answer to (c) at page 7 that the building block approach was at the heart of incentive regulation as practiced by Ofgem (and respectively Offer and Ofgas for electricity and gas before they were combined into a single energy regulator) for the first 20 years of electricity network regulation, and as such incentive regulation delivered impressive efficiency improvements without compromising safety, security, reliability and quality of service, and in many cases improving these quality aspects.[5] The first four items listed under (d) provide assurance to investors that their investments are protected, and, assuming that the return in (ii) is properly calculated, will be sufficient to warrant investing. Items (i)-(iii) imply that the RAB is uprated over time by the increase in the relevant price index, and incremented by investment and decremented by the allowed depreciation. If, as in the UK, revenues and asset values are indexed to the RPI, then the WACC must be also real. It is, however, not essential that the RAB is uprated by the price inflation. In the U.S. the RAB is uprated by nominal investment and depreciation, but the WACC is the nominal interest rate.[6] That has the undesirable effect that the RAB will, under conditions of positive price inflation, fall increasingly below its modern equivalent asset value or optimal deprival value, and as such will represent a front-end loading on consumers of investment that benefits future consumers, but it can still protect investors and survived the test of a lengthy period in US regulatory history.

While a real WACC based approach leads to an appropriate revenue requirement it can, if companies are unable to borrow sufficient index-linked debt, lead to a mismatch in revenues and costs which may create a short-term financeability problem. While not a long-term problem this has been a concern for regulated companies in the UK and had led to regulatory interventions to advance revenue to address the mismatch. This issue was also considered by Ofgem as part of the RPI-X@20 review and was determined to not be a major concern. Further, Ofgem decided that unless companies could prove that they were unable to finance the

[5] See https://www.ofgem.gov.uk/ofgem-publications/51985/performance-energy-networks-under-rpi-x-finalfinal.pdf.

[6] New Zealand also operated a nominal WACC based approach.

short-term mismatch, including through the use of equity, they would be expected to manage the mismatch in costs and revenues.

A more fundamental issue is how the WACC should be determined. The standard approach is the Capital Asset Pricing Model, in which the key parameters are the risk-free rate of interest, the debt premium, the gearing ratio, the cost of equity, and the beta (or correlation with the market). Of these elements, the most contentious is likely to be the gearing ratio, which in turn directly relates to the risk that the utility will be required to bear. Under RIIO it was recognized that placing more risk on utilities would need a higher equity share (lower gearing) or equivalently, a higher WACC, but this was considered desirable if it provided sufficiently more powerful incentives to innovate and reduce costs. This is likely to be the central issue facing the AER, as a move to more aggressive benchmarking and reducing the allowance made for the special circumstances of individual DNSPs will increase regulatory risk and thus raise the WACC. The AER should therefore be required to assess by how much it has raised this risk and the WACC, and whether the cost of the increased WACC is more than offset by the greater efficiency to be reaped.

This is more straightforward if the utilities have traded shares whose price can be used to determine the realized WACC through changes in the ratio of the market to regulatory asset value. If this ratio falls below one, then the WACC used in the determination will have been shown to be too low compared with market expectations. If the utility is state-owned this information is lacking, although it would be realized if the utility were to be privatized.

One potential criticism of the list of building blocks set out in (d) is that it runs into the objections discussed in the RPI @ 20 consultation and which resulted in the shift to totex rather than separate opex and capex regulation in order to incentivize the most efficient combination of operating and capital expenditure. In Britain under RIIO, the onus is placed on companies to make this choice, whereas the NER places this more upon the AER, as set out in NER 6.5.7 (e) (7), which requires the AER if it rejects the company's proposal, to have regard to "the substitution possibilities between operating and capital expenditure." However, one could argue that, if correctly undertaken, the rules should deliver the NEO.

(e) ***To the extent you consider in response to (d) that the correct application of the building block framework is likely to contribute to the achievement of the NEO, if there is a material error in the application of the framework what are the likely consequences for the achievement of the NEO or the purpose of the economic regulation of monopoly electricity distributors referred to above?***

A material error in the application of the building block framework would imply that at least one of the elements of the allowed revenue were either too high or too low.

I shall assume that the NSP would only object if it identified at least one element for which the allowed revenue were too low and by an amount that was material. It would follow that if there were no other material errors that at least offset the error identified by the NSP, then the resulting allowed revenue would be less than the amount required by a correct application of the building block framework. As I have already argued at (d) at page 9 above that a correct application of the building block framework is current best regulatory practice for delivering the NEO, it follows that any material error in applying the building block framework would produce a regulatory proposal that differs from, and therefore would be inferior to, the proposal resulting from the correct application of the building block framework. The onus is therefor upon the AER or another stakeholder to demonstrate that the original proposal also contained other offsetting material errors that if corrected as well as correcting the error found by the NSP would deliver a proposal that would not be materially different from its original proposal.

(f) ***How, if at all, the appropriate regulation of monopoly electricity distributors takes into account the actual financial position of the regulated entity.***

If there is found to be a material gap between the actual and efficient level of opex, as the AER claims, there is the consequential issue of whether the prescribed and very rapid speed of transition to the claimed efficient operating expenditure is likely to contribute to the NEO, and whether it adequately takes account of the actual financial position of the regulated entity. Putting aside the critique of the AER's benchmarking and the reliability of the AER's estimates of the DNSP's efficiencies, the AER's proposal to cut their forecast opex by almost 40% in the cases of Ausgrid and Essential Energy and even 22% in the case of Endeavour Energy is quite clearly an unprecedentedly large cut to their proposed expenditure requirements. Applying these sizes of adjustment as an immediate and full change in the P_0:

- risks prejudicing the financeability of their investment and operations;
- is not in keeping with international precedent; and
- risks being inconsistent with the National Electricity Objective of ensuring the long term interests of consumers with respect to the reliability, safety and security of the national electricity system if sudden opex cost reductions are required.

For example, Meyrick and Associates (Meyrick (2003) in its work for the New Zealand Commerce Commission for its 2004 electricity distribution networks price control noted, in relation to overall prices, that:

Given the capital intensive nature of electricity lines businesses and the long lived nature of the assets involved, it is unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time. Rather, a timeframe of a decade, or two five–year regulatory periods, is likely to be necessary for businesses performing near the bottom of the range to lift themselves into the middle of the pack. This timeframe would allow sufficient time for asset bases to be adjusted significantly, new work practices to be adopted and bedded down and for amalgamations and rationalisations to be implemented and consolidated. It is, however, reasonable to expect profitability levels to be adjusted over a shorter period, say one regulatory period of five years. This should allow sufficient time for adjustment in a sustainable fashion without incurring the risk of financial stress or failure resulting from large P0 adjustments.[7]

I consider it unlikely that such a large reduction, in such a short space of time, to the NSW DNSPs' allowances would not impact on their ability to maintain a reliable and safe network without negatively impacting on their ongoing financeability and viability of the companies as economic entities. If the P0 reduction prejudices cash flow, then commercial credit rating agencies would likely downgrade the credit status of the companies, which would raise their WACC and possibly have a greater impact in raising total costs than the possible incentive effect might have on opex. In the case of the NSWs networks this would impair their ability to remunerate the NSW Treasury for its guarantee, and, if the Government decides to privatize any of these DNSPs, will militate against any desire to maximize their sales value. International precedent indicates that when regulators have identified large inefficiencies they have used regulatory judgment to ensure that a feasible and sustainable price path is set that does not prejudice the companies' credit standings and WACC as Meyrick (2003) in the quote above mentions as "*the risk of financial stress or failure*".

- A further example from international precedent comes from Ofgem. During its fourth electricity distribution price control (DPCR4 for 2005-10), conducted in 2003 to 2004, Ofgem stated that there was a balance to be found between making a P0 adjustment and setting a price path via the X-factor. Ofgem noted that in coming to its decisions it considered two main factors:
- The financial profile of the companies – Ofgem had a duty (and still does) to ensure that DNOs can finance their licenced activities.

That the path of prices reflects cost trends and is sustainable.[8]

(g) ***Please comment on the AER's approach to benchmarking***

I have examined the Draft Decisions for Ausgrid, Endeavour Energy and Essential Energy, and I am working with ACTewAGL on essentially the same set of issues, and

---

[7] Meyrick (2003, page 63), *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996-2003*, a report prepared for Commerce Commission, Wellington New Zealand. The Meyrick report was led by Dr. Denis Lawrence who is now Director of Economic Insights.

[8] Ofgem (2004a), page 111.

will draw on much of the empirical analysis undertaken for ACTewAGL in what follows. I note that the allowed opex and capex as a percentage of those requested by the companies were as follows:

Table 2.1: Allowed opex and capex as a percentage of those requested by the companies

DNSP	Opex	Capex
Ausgrid	60.9%	57.7%
Endeavour Energy	77.3%	61.0%
Essential Energy	61.6%	73.9%

These are material differences, which the AER justifies (in *Attachment 7*) on the basis of inefficiencies identified by their benchmarking exercise; risk assessment, demand forecasts, and changed financial market conditions. If there is a material error, then these are the areas to investigate. The first and most important area to investigate is whether the AER's benchmarking exercise can be relied upon to quantify the gap between the projected opex of the DNSP and the efficient opex determined by the benchmarking and related investigations. Certainly the AER places great weight on the requirement to benchmark the DNSP's initial or base opex to identify inefficiencies, and also defends the robustness of its findings at considerable length at A.2.4. in *Attachment 7*, and claims (at p 7-42) that:

We are in a position to comment upon its reliability for assessing base opex now that we have several benchmarking techniques available to us. We consider that they are reliable. We have multiple techniques and their results support each other.

My investigations, initially of ACTewAGL, but applying more generally to all DNSPs, cast doubt on the claim that the AER has correctly carried out the opex benchmarking, and at least has not given sufficient consideration to the limitations of its opex benchmarking. Even if the AER had correctly identified the DNSPs' inefficiencies, international precedent/ best practice suggests that financial modelling/ financeability testing should be carried out as it is in the consumers' best interests for regulated companies to be able to finance their debt at the lowest efficient cost, as considered under item (f) below and discussed above in the determination of the WACC and the balance to be struck in the risk-reward trade-off.

After reviewing the AER's and its consultant's (Economic Insights) analysis and modelling, it is my opinion that insufficient consideration has been given to the DNSPs' different operating environments within the benchmarking. This is particularly critical as the AER has buttressed its claims for robustness by the use of international data (New Zealand and Ontario, Canada) that does not appear to have been robustly reviewed for operating environment differences either with Australia or across the countries:

> Economic Insights used an international data set capturing distributors in New Zealand and Ontario. The New Zealand and Ontario dataset has allowed Economic Insights to develop more precise parameter coefficients. Together, these two approaches have enabled us to develop more complex models and cross check our benchmarking results. Despite the differing approaches, Economic Insights' benchmarking techniques have produced consistent results. This indicates that the benchmarking findings are robust. (*Attachment 7* p7-46).

Even if operating differences were identified, Economic Insights cites a lack of operating environment variables for Ontario, limiting them to using only the share of underground cables as a proportion of total line length. The only concession that Economic Insights made for the different operating environments across the different countries, besides the 'share of underground cables', is to introduce a dummy variable for NZ and Ontario, i.e. if the DNSP is from New Zealand then the NZ dummy variable will be one, otherwise it will be zero, and similarly for Ontario. Economic Insights stated that the dummy variables:

> pick up differences in opex coverage (as well as systematic differences in operating environment factors such as the impact of harsher winter conditions in Ontario).[9]

Including a dummy variable in the model specification does not necessarily control for these within and across country differences. A dummy variable only controls for level differences between datasets not cost relationship differences.

The AER's data from the Australian DNSPs, from the regulatory information notices (RINs), also causes some concern. The AER used a number of post-modelling normalisations to adjust the frontier target for the NSW service providers. This is not in line with the practices adopted overseas and risks not comparing the DNSPs on a like-for-like basis. One notable areas is capitalisation, where the AER accepted the DNSPs own capitalization policies and which may vary significantly from one DNSP to the next.

I also have concerns that the Australian Regulatory Information Notices (RINs) operating expenditure (Opex) data relied upon by the AER has not been sufficiently normalised for reporting differences before being used in the modelling. The literature around the use of benchmarking for regulatory purposes (for example, Jamasb & Pollitt, 2003;[10] ACCC, 2012[11]) note the importance of ensuring data is collected on a similar basis, is audited, and operating environment differences are controlled for. Jamasb & Pollitt (2001) noted that:

> It is important that the regulators collect national and international data through formal co-operation and exchange. New regulators need to pay ample attention to

[9] Economic Insights (2014, page 31).

[10] Jamasb, T. and Pollitt, M. (2003), 'International benchmarking and regulation: an application to European electricity distribution utilities', *Energy Policy*, 31(15): 1609-1622.

[11] Australian Competition and Consumer Commission (ACCC) (2012), *Benchmarking Opex and Capex in Energy Networks*, Working Paper No.6, Canberra.

> developing good data collection and reporting systems. A precondition for international comparisons is to focus on improving the quality of the data collection process, auditing, and standardisation within and across countries.[12]

Failure to normalise the data may lead to unreliable results, and potentially the choice of inappropriate models or specifications.

The AER stated that it has directly incorporated operating environment factors into its model where possible and where it has not done this it has assessed whether to make additional adjustment. Economic Insights do identify and, with the AER's assistance, quantify some of the differences across DNSPs. The AER has set out in *Attachment 7* (p7-35) of its draft determinations its assessment and response to differences in operating environment and reporting. However, when the AER has made adjustments it has done so to the frontier after the modelling has been conducted. I consider that these differences, particularly the capitalisation policies and greater proportions of high voltage lines, are sufficiently material to be made either through the use of explanatory variables in the modelling or via adjustment prior to conducting the modelling. I consider that making adjustments after the modelling for material differences in companies' cost reporting is not in line with the approach used by Ofgem, the UK electricity and gas regulator, which is considered a leader in the use of comparative benchmarking.

The AER also defends its choice of model specification, which has been criticized by the NSW DNSPs (*Attachment* 7 at 7-44):

> We agree with this point, and Economic Insights has undertaken a careful approach to ensure that its model specifications are appropriate. We consider that Economic Insights' model specifications are the best currently available. Economic Insights' approach to selecting the model specification is objective. It tested its models rigorously to ensure that the results:
>
> - Capture all material inputs and outputs. …

Submissions by the service providers noted that benchmarking does not account for all the variables that might affect network costs.[13] As such, the residual in the models might capture the effect of these variables and not necessarily inefficiency. Like all modelling techniques, benchmarking is limited in the number of variables that it can accommodate. However, we consider that we have captured all of the material variables to the extent that the economic benchmarking data and modelling permit.

To test this claim I have estimated alternative benchmarking models only using Australian RIN data. I have chosen not to use the international data provided by the

[12] Jamasb, T.J., Pollitt, M.G., 2001. Benchmarking and regulation: international electricity experience. *Utilities Policy* 9 (3), page 128.
[13] Ausgrid, *Regulatory proposal: Attachment 5.33*, 2014, p. 6, Endeavour Energy, *Regulatory Proposal: Attachment 0.12*, 2014, p. 7-8, Essential Energy, *Regulatory Proposal Attachment 5.4*, 2014, p. 6.

AER, as I do not consider, given the information readily available and the time I have had to study it, that the reported opex is on a consistent basis across and within countries and that adequate explanatory variables are available. In conducting this modelling I:

- normalised the AER data as best as I can with the information provided and the limited time available;
- incorporated a greater range of operating environment variables; and
- used a range of parametric techniques.

I have not used non-parametric techniques as I believe there was an insufficient number of companies for DEA and the inability to produce descriptive statistics outweighs the benefits of these techniques.

I were unable to consistently produce robust results using stochastic frontier methods (SFA),[14] likely due to the limited number of comparators, but I were able to produce results using Corrected Ordinary Least Squares (COLS) and Random Effects (RE, using a Generalised Least Squares, GLS, estimator). I present a selection of models and their specifications in Table 2.2 below and the efficiency results for the companies from these models in Figure 2.1 and Figure 2.2 below.[15] I ran these specifications using an OLS and RE (GLS) technique. I have included the results from Economic Insights preferred model for comparative purposes and given the full results in an appendix.

[14] The models would not generally converge.

[15] We tested Economic Insights specification of customer numbers, circuit length, ratcheted maximum demand and share of underground cables, however in OLS none of the coefficients were significant and only customer numbers was significant in GLS (RE).

Table 2.2: Model specifications

	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
Functional form*	Cobb-Douglas	Cobb-Douglas	Cobb-Douglas	Cobb-Douglas	Translog	Translog	Translog
Log(Circuit length)	✓	✓	✓	✓	✓	✓	✓
Log(Density - length)	✓		✓	✓	✓	✓	✓
Log(Density – Km^2)		✓					
Log(share of underground cables)	✓	✓	✓	✓	✓	✓	✓
Log(=> 132kV share of circuit)[t]	✓	✓	✓		✓	✓	✓
Log(share of SWER)			✓				✓
Log(RAB additions)	✓	✓		✓	✓	✓	
Time trend	✓	✓	✓	✓	✓	✓	✓

* Cobb-Douglas models require a constant return to scale across DNSPs while translog models allow for varying returns to scale.

[t] Only six of the 13 DNSPs have circuit length at 132kV or above - ACTewAGL, AusGrid, Endeavour, Energex, Ergon and Essential. While the inclusion of this variable may appear to favour these networks, the proportions do vary across the networks and the variable is highly significant in almost all models. This indicates that it is not simply picking up differences (inefficiency or otherwise) between these six networks and the remaining seven.

Figure 2.1: OLS efficiency Scores vs. Economic Insights' preferred model

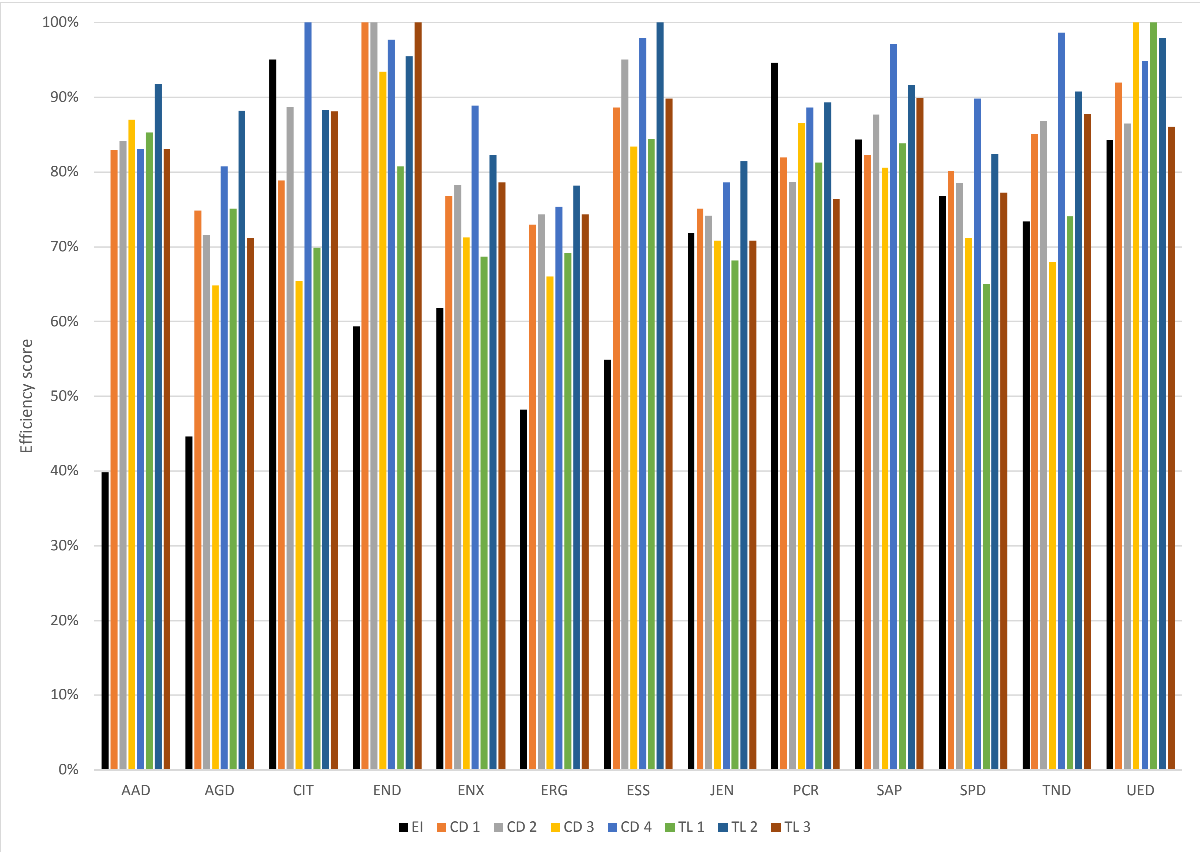
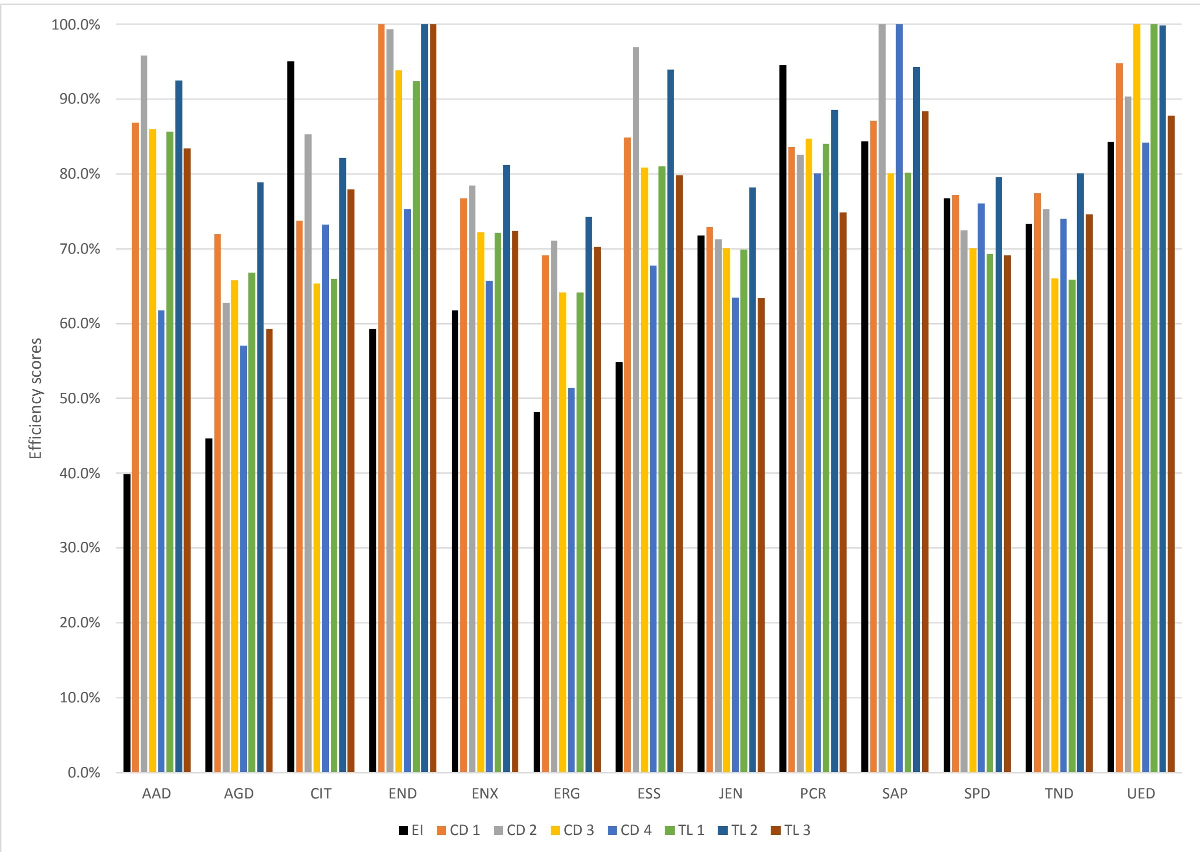


Figure 2.2: RE (GLS) efficiency Scores vs. Economic Insights' preferred model



I found that the modelling was very sensitive to the inclusion of operating environment variables although the models produced a much tighter range of efficiency scores than Economic Insights' model. Our findings indicate that a greater range of operating environment variables are almost certainly required to control for the differences between the DNSPs. However, even simply normalising for differences in the DNSPs' overall cost allocation practices[16] leads to a different efficiency target for the DNSPs.

I have not attempted to identify a preferred model or set of models for benchmarking, rather I have tested whether the AER's benchmarking models had sufficient regard for the cost allocation practices and operating differences between DNSPs.

3. SPECIFIC OBSERVATIONS ON THE REGULATORY FRAMEWORK AND ITS OBJECTIVE IN THE CONTEXT OF THE ACHIEVEMENT OF EFFICIENCIES

(a) *To the extent costs are forecast to be incurred in a regulatory control period (such as redundancy payments) which are associated with the restructuring of a business undertaken to reduce costs in the long-run, what considerations are relevant to the regulatory treatment of such costs, including in the context of a regime that has as its objective one such as the NEO?*

The AER *Explanatory Statement Expenditure Forecast Assessment Guideline* at p225 discusses one aspect of the reasons why costs may be higher for some utilities than for those used to set the benchmark frontier:

> However, Grid Australia identified several operating environment factors relating to different jurisdictional standards that are similar in nature to network complexity, system boundaries and network planning.
>
> Grid Australia considered different jurisdictional standards will affect the level of redundancy in the transmission network where a more stringent standard will lead to higher costs compared to a more relaxed standard. Grid Australia also noted urban planning approvals can vary, which can lead to variances in costs for capital projects between jurisdictions.
>
> However, Grid Australia noted that they did not propose a measure for these factors and did not form a view on the materiality of each factor as this would be best done via sensitivity checks with actual data. Other operating environment factors that do not relate to jurisdictional standards are considered in our operating environment factors section later in this chapter.
>
> For these factors to be included directly into our economic benchmarking model, an appropriate measure of jurisdictional differences would be required. Where a direct

[16] This includes the DNSPs' CAMs, but also their reporting of activities i.e., some DNSPs report an activity as maintenance while other might treat it as replacement expenditure.

> material impact on costs cannot be identified, additional information would be required as a part of a qualitative assessment.
>
> For the three factors listed above, these have been accounted for directly in our templates by either requesting data relating to the actual costs of undertaking the activities or requesting more disaggregated data.

It would seem that jurisdictional differences can be taken into account when determining the efficient level of costs and presumably these could include differences in labour costs arising from differences in agreed working conditions, manning levels, and wage rates for specific roles that might be considerably higher than in the frontier benchmarked companies. This issue is particularly relevant for state-owned enterprises (SOEs) contemplating privatization, where such practices are almost certainly likely to be changed, although typically restructuring would require redundancy payments. The AER *Explanatory Statement Expenditure Forecast Assessment Guideline* at p113 discusses restructuring costs in the context of correcting for the underlying rate of productivity growth:

Similarly, Incenta Economic Consulting stated, in a report prepared for Grid Australia, that while the opex partial productivity growth forecast included in the opex 'rate of change' should include the effects of economies of scale and changes in business or operating environment factors, it should not include the residual time trend element. Incenta noted that, while it agreed with the inclusion of the technology-related component of the residual time-trend element, it was concerned that this could not be separated from other elements that might be of a 'one-off' nature and not be repeatable in the next regulatory period. Incenta cited four such factors it considered would be inappropriate to include the effects of:

1. the effect of the less efficient firms 'catching up' to their peers, to the extent that this effect had not been able to be eliminated though alternative means
2. productivity growth that is a consequence of efficiency-improving capital expenditure
3. productivity growth that is the consequence of past one-off operating expenditures (such as corporate restructures and/or redundancy costs) that may have been excluded from consideration or not fully reflected in the productivity time trend
4. a reduction in productivity growth resulting from new obligations being imposed on NSPs.

The consequences of restructuring on subsequent productivity growth can be considerable, as the *Guidelines* demonstrates at p113:

> Economic Insights' study found that, of the three Victorian gas distribution businesses, Multinet and Envestra Victoria had strong productivity growth in the post privatisation era of 1999 to 2005. Their productivity growth was more modest

> from 2005 to 2011 after they became relatively efficient. SP AusNet, on the other hand, had relatively flat productivity performance from 1999 to 2004 but then exhibited stronger productivity growth from 2004 to 2010. Because the operating cost function was estimated using a sample of 144 observations from 11 gas distribution businesses, the residual time trend element included in the opex partial productivity forecast for SP AusNet was 0.6 per cent per annum, despite SP AusNet having exhibited opex partial productivity growth of 8.4 per cent per annum over the last five years of the sample."

Higher productivity growth resulting from the restructuring precipitated by a change of ownership or regulatory regime is thus not unexpected, and the question is how this should be treated in the price control that will come into effect at the time of the restructuring. The AER is quite explicit on how it proposes to deal with restructuring costs, and argues that the DNSPs should bear the full cost of restructuring:

> On the information before us, we are not satisfied that the NSW service providers have made a sufficiently robust argument for why consumers should share in funding their transition to an efficient level of opex. (*Attachment 7* p7-52)

On the question of higher labour costs which the DNSPs argued were obligations under the *Fair Work Act 2009*, the AER argues that legally these are not a 'regulatory obligation or requirement' under the NEL (*Attachment 7,* p7-52-3) and thus the DNSP's argument fails. More generally, the AER states:

> We do not approve a particular EBA or any other plan of expenditure when we set a total opex allowance. When a service provider enters into an agreement of any kind, it does so in a context where it knows that a particular allowance will apply for five years, but there is no guarantee that the same or a similar allowance will be approved for the following five year period.
>
> If a service provider ultimately spends inefficiently or imprudently, it will bear those additional costs and, conversely, if it achieves efficiencies it may make additional profits. This is a core feature of incentive based regulation and is intended to reflect the conditions that would be faced by businesses operating in a competitive environment.
>
> We must be satisfied that the total opex forecast reasonably reflects the efficient costs of a prudent operator (not the service provider in question), given reasonable expectations of demand and cost inputs, to achieve the opex objectives. (*Attachment 7*, p7-53).

In the past it appears that such DNSP-specific costs were allowed under the old NEL, but the wording that allowed that has been deleted, and the reference is now only to "the efficient costs of a prudent operator (not the service provider in question)". However, that does not mean that the AER can ignore the specific circumstances of the DNSP, as the AEMC explained when agreeing to remove the reference to the circumstances of the relevant NSP:

> The Commission is of the view that the removal of the "individual circumstances" clause ***does not enable the AER to disregard the circumstances of a NSP in making a decision on capex and opex allowances***. Benchmarking is ***but one tool*** the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal. Should the phrase remain, it appears that the AER's interpretation of it may ***restrict it from utilising appropriate benchmarking*** approaches to ***inform*** its decision making. The Commission considers that the removal of the "individual circumstances" phrase will ***clarify the ability of the AER to undertake benchmarking***. It assists the AER to determine if a NSP's proposal reflects the prudent and efficient costs of meeting the objectives. That ***necessarily requires a consideration of the NSP's circumstances*** as detailed in its regulatory proposal. Under the first expenditure criterion the AER is required to accept the forecast if it reasonably reflects the efficient costs of achieving the opex objectives. These include references to the costs to meet demand, comply with applicable obligations, and maintain quality, reliability and security of supply of services and of the system. These ***necessarily require an assessment of the individual circumstances*** of the business in meeting these objectives. So to the extent that different businesses have higher standards, different topographies or climates, for example, these provisions lead the AER to consider a NSP's individual circumstances in making a decision on its efficient costs.[17] (***Emphasis added***.)

It is clear from the emphasized elements that the removal of the phrase was to clarify the approach to any benchmarking, and not as a general argument that no special circumstances can be allowed. Indeed, the AEMC was far stronger in pointing out that the costs of meeting the NEO would ***necessarily require an assessment of the individual circumstances*** of the business in meeting these objectives. These include the costs of restructuring and redundancy payments.

The relevant question is therefore not, as the AER claimed, why consumers should bear some or all of the transition costs, but how these costs should be treated in the price control. The simplest approach, essentially adopted at the privatization of the Distribution Companies in England and Wales, was to ignore the potential for cost reduction (at that time, unknown, as it was before benchmarking became standard practice), and allow the DisCos to decide whether to pay the costs of restructuring, given that they would be allowed to recoup the resulting cost reductions until the next price control, after which there would be a likely step change in the initial price level (a P_0 adjustment).

The alternative is to predict that there is likely to be a considerable improvement in productivity as a result of restructuring to reach the efficient frontier, and take that into account in setting the P_0, but then logically the adjustment costs ought to be treated as necessary investment to deliver that productivity boost.

---

[17] AEMC, *Final Rule Determination - National Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p.107

Which approach (or combination) is better depends on the degree of informational asymmetry. If the DNSP knows best how to restructure, then some form of glide path may avoid the need for the AER to micro-manage the process of restructuring (or at least work out what needs to be done and what that would cost). If the AER has no confidence that the DNSP knows what to do, or lacks the will to do it, then the AER might make an estimate of what other companies have spent and what productivity boost they achieved, and adjust the allowed Opex accordingly. But either way it would be unreasonable for the AER to expect instant movement to the efficient frontier with no attendant costs, of which redundancy payments are the most obvious.

The consequences of requiring the DNSP to bear all the past costs that are now deemed to have been inefficient would be to raise doubts in the minds of shareholders about the risks of future regulatory settlements. If changes in law and expenditures that experience shows with the benefit of hindsight to have been unwise are all to be borne by the utility, then regulatory risk will be increased. If the costs of all past mistakes are to be borne by shareholders, but the benefits of all prudent choices are to be passed through to consumers via the shift in the efficient frontier, then the risks of operating such DNSPs will have increased, and the required WACC will rise. That in turn will either be allowed by the AER, in which case consumers will have to bear that part of the higher cost, or the higher WACC will not be accepted, in which case the DNSP will struggle to raise sufficient funds for investment and will either have to cut opex or capex, to the detriment of current or future consumers. As noted above in the answer to (c) at page 7, a small increase in the WACC when applied to a large Regulatory Asset base (RAB) could easily outweigh a considerable reduction in operating costs (opex), prejudicing the long term interests of consumers. Thus the key to good regulation is securing the right balance of risk and reward to place on the utility.

(b) ***Review and comment on Attachment 7 to the draft determination. Without limiting the passages to which you should have regard in undertaking your review, we draw attention to the following passages:***

(i) the following extract from the AER's draft determination which appears on page 7-42 of Attachment 7 to the draft determination:

"The NSW service providers do not disagree with making efficiency adjustments. Each of their regulatory proposals recognises a need to move towards a more efficient cost base. However, the service providers have proposed incremental adjustments to remove inefficiency and have sought to recover some of the costs of these efficiency adjustments. This approach is inconsistent with the requirement for forecasts of expenditure to reasonably reflect the prudent and efficient costs of achieving the opex objectives.

Further, under this approach consumers would bear not only the costs of removing inefficiencies but fund the inefficiencies themselves.

Also, the NSW service providers have, in our view, taken a flawed approach to identifying inefficiency because their approach does not incorporate top down benchmarking. It is necessary to consider the efficiency of providing services overall rather than the efficiency of specific activities. The NSW service providers have proposed incremental efficiency adjustments that apply to specific activities. This approach focuses on certain aspects of performance in isolation, which ignores the trade-offs of delivering different output combinations. Under this approach, a service provider could offset the savings it identifies for one output by increasing costs for another." (footnote omitted)

(ii) *on page 7-16, the paragraph commencing "As outlined in our Guideline";*

(iii) *pages 7-26 and 7-27;*

(iv) *page 7-33;*

(v) *section A.2.5 ("Implementing efficiency improvements") (pp 7-51 to 7-54); and*

(vi) *pages 7-166 and 7-167 (the section under the heading "Cost base restructure and efficiency program").*

Before considering the AER's specific obligations under the NER for assessing opex, it is appropriate to bear in mind two key points regulators should consider in relation to setting efficiency targets for regulated companies:

- how much confidence can be placed on the assessment approach used to determine opex efficiency (regardless of whether the approach was based on top-down model(s), bottom-up engineering assessment or a combination); and
- given the magnitude of a company's estimated inefficiency, what is a reasonable speed at which it can close the efficiency gap without compromising the overall regulatory objective.

The simple interpretation of these points is that the less confident a regulator is of the assessment then the more cautious it should be in setting targets for cost reduction and translating these into allowed revenues. If there is a significant gap to close then it is more likely that the regulated company will need longer to close it. If either of these points are violated and if the efficiency gap is large then the company's financing costs will increase and its continuing operation may be affected. Holding these points in mind, it is important to understand how and against what criteria the AER undertook its assessment of the NSW service providers' operating expenditure (opex). The NER rules provide specific guidance; in assessing opex the AER must have regard to the NER opex criteria described in NER 6.5.6(a).[18]

After receiving the DNSP's regulatory proposal, the AER must either accept or reject the DNSP's proposed forecast opex on the basis of the operating expenditure criteria described in NER 6.5.6(c) and (d).[19] I reproduce 6.5.6(c)(2) below:

> (2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and …

In undertaking its assessment, the AER is required to take into account the operating expenditure factors. The operating expenditure factors are described in NER 6.5.6(e).[20]

The NER is specific in regards to the opex building block, but it is not specific on whether (or how) the opex building block should be considered in relation to the overall revenue requirements of the regulated company, aside from explicitly recognizing the opex/ capex trade-off. The use of the term "prudent" in NER 6.5.6(c) is therefore of critical importance in my opinion. NERA (2014) considered that a critical aspect of 'prudence' is the process and reasoning that is followed by DNSPs in developing their forecasts.[21] Extending this interpretation to the 'sustainability' of the network, it would be imprudent for a DNSP not to consider the financial impacts as well as its reliability and quality of service from significantly reducing its opex in a very short space of time. The DNSP must have regard to the long-term and this will include considering how staff may be employed over the longer-term and ensuring sufficient expertise is available. For instance, Ofgem made significant allowances for 'workforce renewals' during its fifth electricity distribution price control (DPCR5) to ensure that there were sufficient skilled staff to cope with increases in capex work and an aging workforce.[22]

In *Attachment 7*, the AER make numerous references to a service provider being prudent in improving its efficiency. On page 7-16:

> As outlined in our Guideline, if the prudent and efficient opex allowance to achieve the opex objectives is lower than a service provider's current opex, we would expect a prudent operator would take the necessary action to improve its efficiency. We would expect a service provider (including its shareholders) to wear the cost of any inefficiency. To do otherwise, would mean electricity network consumers would fund some costs of a service provider's inefficiency. Accordingly, if our opex forecast is lower than a service provider's current opex we would generally not consider it appropriate to provide a transition path to the efficient allowance. This approach

[18] *National Electricity Rules 6.5.6, Version 65, 1 October 2014.*
[19] *National Electricity Rules 6.5.6, Version 65, 1 October 2014.*
[20] *National Electricity Rules 6.5.6, Version 65, 1 October 2014.*
[21] NERA (2014), *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules: Supplementary Report,* prepared for AusGrid.
[22] Ofgem (2009a), *Electricity Distribution Price Control Review: Final Proposals.*

> appears to be reflected in the NER, which provides that we must be satisfied that the opex forecast reasonably reflects the efficient costs of a prudent operator given reasonable expectations of demand and cost inputs to achieve the expenditure objectives.[23]

On page 7-166:

> For instance, while total opex is relatively recurrent, categories of opex, or opex on projects and programs are not recurrent. That means each year a service provider could spend more opex on some areas (such as asbestos management) and less opex on other areas. A prudent and efficient service provider could increase compliance with existing regulations by redirecting funds from categories of opex which were expected to decline in the forecast period. Alternatively it could do this by reprioritising its opex budget. We see no reason why a prudent and efficient service provider would need to seek additional funding from consumers to meet existing regulatory obligations above an efficient base amount of opex.

While a prudent operator should target improved efficiency it should do this in a sustainable and 'prudent' way. In other words, the NSW service providers must take a prudent approach to managing its workforce to achieve an efficient level of opex. This may be by managing 'stranded'[24] labour due to a reduction in capex and/or planning for future investment. Given their forecast work plans at the time it may have been prudent and efficient for the NSW service providers to ensure that they had the capacity and capability available to undertake future network investment. If the infrastructure 'boom' had continued they may not have been able to source sufficient external contractors or they may have faced a significantly higher cost in securing these services. Therefore, the EBAs may have seemed cost-efficient at the time. Requiring the NSW service providers to bear the full cost of this in a short space of time seems unreasonable and raises regulatory risk.

Ofgem has noted in the past, in relation to electricity distribution companies, that "when allowances are being cut significantly it can take more time to restructure and become more efficient."[25] While Ofgem has taken a harder line in its most recent review with opex allowances adjusted through a full P_0 adjustment, Ofgem justifies this by the length of time the networks have been subjected to comparative assessment and relative convergence achieved (the largest opex reduction relative to actual historical spend at RIIO-ED1 was 11%). Ofwat, the England and Wales water regulator, also has a long history of using comparative assessment for setting opex allowance. It too has applied discretion in the past in determining how quickly inefficient regulated companies might close the gap to efficient companies. In its 2004 price control (PR04), Ofwat stated that it made "judgements about the speed

[23] AER, AusGrid Draft Determination: Attachment 7, page 7-16.
[24] AER, AusGrid Draft Determination: Attachment 7, page 7-18.
[25] Ofgem (2009b), *Electricity Distribution Price Control Review: Cost assessment*, page 11.

and extent to which it [a company] can catch up with the performance of the best."[26] Similarly, Meyrick and Associates (Meyrick (2003, p63 cited above)[27] in advising the New Zealand Commerce Commission its 2004 electricity distribution networks price control argued that it was "unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time."

It would seem unreasonable to make reductions to opex allowances of between 22.7% (to Endeavour) and 39.1% (to AusGrid) (see Table 2.1) in a single year without consideration for the NSW service providers' financial positions, long-term plans and deficiencies in the econometric modelling.[28] The latter point is discussed in more detail below.

The AER stated that it has used a number of different techniques to assess base opex however it has predominantly relied on a single top-down Cobb-Douglas stochastic frontier model (SFA). The model was developed by Economic Insights and uses data from Australia and two other international sources – from Ontario and from New Zealand.[29] The AER made two adjustments to the frontier determined via the model, the AER:

- make a 10% allowance for operating differences between the NSWs Networks and the frontier companies; and
- compares the NSW service providers to an average efficiency of all the networks with efficiency scores above 0.75 (75%).
- The AER stated (page 7-42) that the NSW service providers' approach was inappropriate as it does not consider top-down analysis.

Using a top-down model to assess opex (or totex) is consistent with best practice in the UK as it does not enforce choices on the companies as to which activities to undertake, however, using only a single model with few explanatory variables and no bottom-up assessment is not best practice. For instance, Ofgem in its RIIO-ED1 decision stated:

> Our use of three models [two top-down and one bottom-up] acknowledges that there is no definitive answer for assessing comparative efficiency and we expect the models to give different results. There are advantages and disadvantages to each approach. Totex models internalize operational expenditure (opex) and capital expenditure (capex) trade-offs and are relatively immune to cost categorisation issues. They give an aggregate view of efficiency. The bottom-up, activity-level

[26] Ofwat (2004), *Future water and sewerage charges 2005-10: Final determinations,* page 12.
[27] Meyrick (2003), *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996-2003*, a report prepared for Commerce Commission, Wellington New Zealand.
[28] AER, AusGrid Draft Determination: Attachment 7, pages 7-26 to 7-27.
[29] AER, AusGrid Draft Determination: Attachment 7, pages 7-18 to 7-19.

> analysis has activity drivers that can more closely match the costs being considered.[30]

Ofgem weighted its three models together and set the frontier (based on the upper quartile company) after they have been combined to avoid 'cherry-picking' i.e. to avoid selecting the upper quartile performer across all models which would set an unrealistic target. Note that the AER has made a superficially similar target:

> Rather, on the advice of our expert consultant, to allow for potential modelling and data error, we have benchmarked the NSW service providers against the weighted average efficiency of service providers with a score of 0.75 or higher. (*Attachment 7* p7-45).

My review of precedent from regulators in other jurisdiction indicates that regulators choose a frontier taking into account a range of factors, including their confidence in the data, techniques and robustness of the modelling. While the AER's method is not one I have seen before, it is not in principle dissimilar to a commonly used approach of adjusting the frontier to a company placed on the upper quartile (or upper third) of the results, albeit that these are applied to non-SFA techniques.

However, the AER's approach has several undesirable features, as the actual benchmark will depend on the weights of different DNSP's and their distance from the frontier, and as such will likely move in unpredictable ways over time. It is worth noting that the seminal article on yardstick competition[31] used the average of all other firms as the benchmark) although the median or a quartile have the advantage of being less prone to outliers and errors.

The AER's approach of averaging the efficiency over companies that achieve an efficiency score of at least 75% is also very model specific. If a different specification was run and all companies achieved efficiency score of over 75% then the AER's approach would not work. While discretion should be used when choosing a frontier, I consider that it is likely to be more practicable to use an approach that can be used consistently across models.

Evidence from international regulators indicate that measurement error plays a significant part in their decisions on where to set the frontier and how much to 'aim-off' this. The regulator also takes into account the specification of the models, whether the drivers used in the modelling do not take account of (or differentiate between) all the costs faced by the regulated companies, and then adjustments to allowances may be made.

---

30 Ofgem (2014), *RIIO-ED1: Final determinations for the slow-track electricity distribution companies: Business plan expenditure assessment*.

31 Shleifer, A. (1985) "A theory of yardstick competition", *Rand Journal of Economics*, 16(3) 319-27

Jamasb & Pollitt (2001)[32] noted that:

> Average benchmarking methods may be used to mimic competition among firms with relatively similar costs or when there is lack of sufficient data and comparators for the application of frontier methods.

I interpret "sufficient data" to also mean the quality and robustness of the data as the authors discuss these issues in latter sections of their paper.

In relation to 'aiming-off' the frontier, regulators have shown a large degree of discretion in determining the extent to which inefficient companies need to close the gap to the frontier and how quickly they need to do this. This is even after the regulator has used its discretion in choosing a frontier. In making their judgement regulators take into account:

- the robustness of the data;
- the modelling technique used;
- the choice of the 'frontier'; and
- the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.

It is often the case that regulators are required to take into account both the interests of consumers and the ongoing financeability of an efficient regulated company. If a regulator were to set either an unrealistic or unachievable efficiency target for regulated companies then both of these aims may be put at risk.

If there is a material error in the application of the building blocks then at the extreme a regulated company would face difficulties in raising finance to continue its operations. Therefore, the quality, reliability, safety and security of the electricity distribution system would be called into questions as the service providers would need to prioritise or reduce its services.

While there is a move towards more aggregate level benchmarking, Ofgem's approach makes sense in regards to mix of explanatory variables it includes in its modelling. For instance, one would not expect network length and customer numbers to explain whether a network is predominantly located in an area of dense vegetation thus requiring proportionately more vegetation management than its peers.

Given the limitations of the model the AER has relied on, albeit with supporting analysis, one might expect the AER to employ a greater degree of caution than making *ex-post* adjustments to the frontier and averaging across the companies with

[32] Jamasb, T.J., Pollitt, M.G., 2001. Benchmarking and regulation: international electricity experience. *Utilities Policy* 9 (3), 107-30

efficiency scores above 0.75. For example, Meyrick (2003) in its work for the New Zealand Commerce Commission for its 2004 electricity distribution networks price control noted that while it had identified a substantial range (around 30%) in companies' efficiency "[g]iven the need to minimise risks given the variable quality of the available data and residual uncertainties, we reduce the range of C factors [relative productivity and profitability factors] to –1, 0 and 1 per cent".[33]

[33] Meyrick (2003, p63), *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996-2003*, a report prepared for Commerce Commission, Wellington New Zealand.

4. DECLARATION

The opinions contained in this report are based wholly or substantially on the specialised knowledge gained through training, study and experience outlined in the Curriculum Vitae that is attached in **Error! Reference source not found.**.

I have made all inquiries that I believe are desirable and appropriate and that no matters of significance that I regard as relevant has, to my knowledge, been withheld from the Court.

Professor David Newbery, Chairman, CEPA Ltd

ANNEX A ECONOMETRIC RESULTS

Table A.1: OLS alternative model specifications[34]

Variable	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
Functional form/estimator/data structure	Cobb-Douglas/ pooled	Cobb-Douglas/ pooled	Cobb-Douglas/ pooled	Cobb-Douglas/ pooled	Translog/ pooled	Translog/ pooled	Translog/ pooled
Log(Circuit length)	0.520***	0.357***	0.931***	0.488***	0.952***	0.628***	0.384***
Log(Density - length)	0.471***		0.914***	0.277**	0.858***	0.564***	
Log(Density – Km^2)		0.087***					0.081**
*Log(length)^2					0.171	0.187*	-0.006
*Log(density)^2					0.480***	0.229*	0.008
*Log(length*density)					0.512***	0.360**	0.013
Log(share of underground cables)	-0.155**	-0.047	-0.269**	-0.081	-0.181	-0.165**	
RAB additions	0.378***	0.508***		0.518***		0.359***	0.482***
Log(=> 132kV share of circuit)	0.039***	0.027**	0.077***		0.057***	0.026**	0.028
Log(share of SWER)				-0.040*			
Year	0.004	-0.01	0.043***	-0.014	0.042***	0.006	-0.009
Constant	-0.822	26.984	-73.815***	34.543	-73.129***	-4.827	24.712
Additional statistics							
R-squared	0.98	0.975	0.963	0.975	0.971	0.984	0.975

*Significance stars: ***1%, **5%, *10%*

[34] All scale variables shown at the sample mean.

Table A.2: RE (GLS) alternative model specifications[35]

Variable	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
Functional form/estimator/data structure	Cobb-Douglas/ pooled	Cobb-Douglas/ pooled	Cobb-Douglas/ pooled	Cobb-Douglas/ pooled	Translog/ pooled	Translog/ pooled	Translog/ pooled
Log(Circuit length)	0.708***	0.609***	0.946***	0.767***	0.955***	0.758***	0.552***
Log(Density - length)	0.630***		0.933***	0.495***	0.939***	0.672***	
Log(Density – Km^2)		0.150***					0.126***
*Log(length)^2					0.02	0.08	-0.117
*Log(density)^2					0.04	0.091	0.001
*Log(length*density)					0.047	0.134	-0.041
Log(share of underground cables)	-0.147*	-0.007	-0.257**	0.001	-0.251*	-0.143	
RAB additions	0.215***	0.258***		0.278***		0.215***	0.230***
Log(=> 132kV share of circuit)	0.053***	0.050***	0.077***		0.076***	0.046***	0.062***
Log(share of SWER)				-0.021			
Year	0.019***	0.012*	0.043***	0.006	0.042***	0.019***	0.015***
Constant	-28.400**	-14.419	-73.380***	-3.532	-73.079***	-27.708**	-20.025*
Additional statistics							
R-squared[t]	n/a	n/a	n/a	n/a	n/a	n/a	n/a

*Significance stars: ***1%, **5%, *10%*

[t] *R-squared values provided by GLS models in STATA (the estimation software I used) are not meaningful.*[36]

[35] All scale variables shown at the sample mean.
[36] See Greene (2008), page 156.

ANNEX B CURRICULUM VITAE

Professor David Newbery, CEPA Vice-Chairman

Summary
I am CEPA's Chairman. I am a Research Fellow in the Control and Power Research Group at Imperial College London and Emeritus Professor of Applied Economics at the University of Cambridge, where I was Director of the Department of Applied Economics from 1988 - 2003. I am Research Director of the Electricity Policy Research Group at the University of Cambridge, a multi-disciplinary research group supported by public funding from various Research Councils and support from stakeholders in industry and regulatory agencies. I was the 2013 President of the International Association for Energy Economics. I spent two years as a Division Chief in the World Bank and have been a visiting Professor at Berkeley, Princeton, Stanford and Yale. I am a fellow of both the Econometric Society and the British Academy. I am the Deputy Independent Member of the Single Electricity Market of the island of Ireland, and was Chairman of the Dutch Electricity Market Surveillance Committee from 2001-5 and a member of the Competition Commission from 1996 to 2002. I am an internationally recognised expert on economic regulation and reform of network industries and the transport sector. I have led and participated on numerous CEPA assignments in the Economic Regulation and Competition practice area for clients such as the UK's Ofgem (Office of Gas and Electricity Markets), the Portuguese Competition Commission, the Dutch Office of Energy Regulation and other regulatory agencies and regulated companies. My publications include the book *Privatization, Restructuring and Regulation of Network Utilities* (MIT Press, 2000). I was the guest editor of *The Energy Journal* (2005) issue on European electricity liberalisation, and the recipient of a Festschrift "Papers in Honor of David Newbery: The future of electricity" in *The Energy Journal* (2008).
Selected Experience
• Expert Advisor during the preparation for first electricity price control in the Netherlands. Then acted as Chairman of the Dutch Electricity Market Surveillance Committee between 2001 and 2005. **Experience as CEPA's Chairman:** • Expert Advisor, Market power and liquidity in the Single Electricity Market (SEM) for CER/NIAUR. David was the expert advisor for CEPA's high profile advice on how to promote competition and liquidity in the SEM. The advice covers: (i) sources of market power in the SEM; (ii) the degree and quality of liquidity in the SEM; and (iii) likely changes to market power and liquidity over the next 10 years. • Expert Advisor, CEPA detailed study for DEFRA determining the direct and indirect costs and benefits to the Russian Federation from ratifying the Kyoto Protocol. • Expert Advisor, CEPA study for the Dutch electricity regulator NMa on the economic issues associated with the potential development of a new electricity interconnector between the UK and the Netherlands, called BritNed. • Expert Advisor, CEPA support to the Irish Commission for Energy Regulation for the price control review of the gas transmission and distribution networks for 2007-2012. • Expert Advisor, CEPA advice to Northern Ireland's Strategic Investment Board on how to ensure that the water reform strategy is effective, efficient and meets its stated goals, particularly with respect to the removal of the need for government subsidy. • Expert Advisor, part of a CEPA team that carried out an international comparison of the approaches regulators adopt to determining the appropriate cost of capital allowance, carried

out for the Dutch electricity regulator.

Advisory experience in infrastructure sector:

- Member of World Bank teams advising the governments of Hungary, the Czech Republic and Bulgaria on regulatory reforms and restructuring of the electricity, gas and oil sectors needed to meet the European Community Electricity Directives and improve sector performance.
- Worked with CET on preparing the privatisation of Poland's 33 electricity distribution companies.
- Consultant to the National Treasury of South Africa on the reform of the electricity industry 2007-8 providing a range of expertise and advice on the structure of the market and the impact of proposed policy changes on the marker participants.
- Occasional consultancies to the Dutch Ministry of Economic Affairs, most recently on policy towards electricity mergers (January, 2003); policy towards electricity security of supply (September 2002); experience of Dutch 3-G spectrum auction (via Erasmus university, Rotterdam); cost-benefit analysis of Schiphol Airport expansion (January, 2001).
- Co-Project Director, series of studies for Portugal's Competition Authority examining the gas and electricity markets, proposed mergers and remedies to mitigate any effects on competition.
- Provided economic advice to Ofgas and then Ofgem under an annually renewed sequence of contracts. Under the final contract, David advised on methodology for setting gas transport tariffs, storage, price reviews, the regulatory asset base, and a variety of ad hoc issues. David advised Ofgas on the network code and the regulation of TransCo; Ofgem and Offer on use-of-system pricing and reforms of the pool.
- Wrote a report on Ofgem's project TransmiT on setting transmission tariffs, and co-authored a report on Ofgem's Integrated Transmission Planning and Regulation.
- Wrote a report for DG-ENER on the benefits of electricity market integration, and another on long-term contracts for interconnector use.
- Directed a sequence of four large research projects on the British energy markets under contracts with the ESRC (1989-2003), and several projects studying tax reforms and the transition of Hungary to the market economy, financed by the ESRC, PHARE, & ACE.

Qualifications

2001	ScD, University of Cambridge
1976	PhD Economics, University of Cambridge
1968	MA Economics, University of Cambridge
1965	Part II Economics (First) , University of Cambridge
1964	BA Economics, University of Cambridge
1963	Part II Mathematics Tripos, University of Cambridge

Employment History

2001 – present	Chairman, CEPA
1988 – present	Professor of Applied Economics, University of Cambridge
1988 – 2003	Director of Department of Applied Economics, University of Cambridge
1987 – 1988	Ford Visiting Professor at University of California, Berkley
1985 and 1987	Visiting Professor, Princeton University; Visiting Scholar, IMF
1981 – 1983	Division Chief, World Bank, Washington, D.C.

1966 – 1988	Lecturer then Reader in Economics; Fellow and Director of Studies in Economics, Churchill College, University of Cambridge

Professional Positions

- President, European Economic Association (1996)
- President of the International Association for Energy Economics, 2014
- Member of the Competition Commission (1996 – 2002)
- Member of the Environmental Economics Academic Panel, Department of the Environment (now Defra)
- Harry Johnson Prize of Canadian Economic Association (1993)
- Fellow of British Academy (1991)
- CBE 2012
- Frisch Medal of the Econometric Society (September 1990)

Selected Publications

Book

- Newbery, D.M. (2000), *Privatization, Restructuring and Regulation of Network Utilities*, (The Walras-Pareto Lectures, 1995), MIT Press, 2000, ISBN 0-262-14068-3 pp466+xvi. See http://mitpress.mit.edu/books/privatization-restructuring-and-regulation-network-utilities

Journal Articles

- Strbac, G, R. Green, C.V. Konstantinidis, I. Konstantelos, R, Moreno, D.M. Newbery and M. Pollitt, "Electricity Transmission Arrangements in Great Britain: Time for Change?" *Energy Policy*, forthcoming
- Newbery, D.M. (2012) 'Contracting for wind generation' *Economics of Energy & Environmental Policy,*1(2) pp.19-36, and EPRG 1120 at http://dx.doi.org/10.5547/2160-5890.1.2.2
- Newbery, D.M. (2012) 'Reforming Competitive Electricity Markets to Meet Environmental Targets' *Economics of Energy & Environmental Policy,* 1(1), pp 69-82
- Newbery, D.M. (2010) 'A Nuclear Future? UK Government policy and the role of the market' *Economic Affairs*, June
- Newbery, D.M. (2009) 'Market design for a large share of wind power', *Energy Policy* pp. 3131-3134 at http://dx.doi.org/10.1016/j.enpol.2009.07.037 15 August on line
- Roques, F.A., D. M. Newbery and W. J. Nuttall (2008) 'Fuel mix diversification incentives in liberalized electricity markets: a Mean-Variance Portfolio Theory Approach' *Energy Economics* Vol 30/4 pp 1831-1849 (available as EPRG Working Paper 06/26), available at http://dx.doi.org/10.1016/j.eneco.2007.11.008

- Newbery, D.M. (2008) “Climate change policy and its effect on market power in the gas market”, *Journal of European Economic Association*, June 6(4), 727-51 (available as EPRG Working Paper 05/10)
- Brunekreeft, G. and Newbery, D. (2006) ‘Should Merchant Transmission Investment be Subject to a Must-offer Provision? , *Journal of Regulatory Economics*, Nov, 30(3), 233-60
- Jamasb, T., D. Newbery and M. Pollitt (2006) ‘Core Indicators for Determinants and Performance of Electricity Sector in Developing Countries’, *International Journal of Regulation and Governance* 6(1): 79–114, (CMI EP 46)
- Roques, F. A., W. J. Nuttall, D. M. Newbery, R. de Neufville, S. Connors (2006) “Nuclear Power: a Hedge against Uncertain Gas and Carbon Prices?” *The Energy Journal,* 27, (4) 1-24
- Twomey, P., Green, R., Neuhoff K., Newbery, D. (2005), ‘A Review of the Monitoring of Market Power’, *Journal of Energy Literature* 11 (2): p. 3-54 (also as CMI/DAE Working paper 71)
- Roques, F.A., D.M. Newbery and W.J. Nuttall (2005) ‘Investment incentives and electricity market design: the British experience’, *Review of Network Economics*, 4 (2), 93-128
- Newbery, D.M. (2005) “Electricity liberalisation in Britain: the quest for a satisfactory wholesale market design”, *Energy Journal*, Special Issue on European Electricity Liberalisation, ed. D Newbery, 43-70
- Newbery, D.M. (2005) ‘Why tax energy? Towards a more rational policy’, *Energy Journal*, 26 (3), 1-39
- Newbery, D.M. (2005) ‘Integrating electricity transmission systems’, *Utilities Policy,* 13 (2), June, 69-72.
- Brunekreeft, G., Neuhoff, K. and Newbery, D. (2005) ‘Electricity transmission: an overview of the current debate’, *Utilities Policy,* 13 (2), June, 73-94.
- Neuhoff, K. and D.M. Newbery (2005) ‘Evolution of energy markets: does sequencing matter?’, *Utilities Policy,* 13 (2), June, 183-174.
- Gilbert, R.J., K. Neuhoff and D.M. Newbery (2004) ‘Mediating market power in electricity networks’, *Rand Journal of Economics,* 35 (4) Winter 691-711.
- Newbery, D.M. (2003) ‘Network capacity auctions: promises and problems’, *Utilities Policy*, 11, 27-32
- Newbery, D.M. (2003) ‘Regulatory challenges to European electricity liberalisation’ *Swedish Economic Policy Review*, 9(2), Fall, 9-44.

- Newbery, D.M. (2002) 'Regulating Unbundled Network Utilities', *Economic and Social Review*, 33(1), Spring, 23-42. (available at http://www.econ.cam.ac.uk/dae/people/newbery/index.htm)
- Newbery, D.M. (2002) 'Problems of liberalising the energy utilities', *European Economic Review*, 46, 919-927. (available at http://www.econ.cam.ac.uk/dae/people/newbery/index.htm)

Chapters in Books

- Newbery, D.M. (2013) "Evolution of British electricity market and the role of policy for the regulation toward low carbon future", Ch.1, pp3-33 in *Evolution of Global Electricity Markets: New paradigms, new challenges, new approaches,* Elsevier June 2013 Edited by Fereidoon P. Sioshansi (http://www.amazon.com/Evolution-Global-Electricity-Markets-challenges/dp/0123978912)
- Newbery, D.M. (2010) 'Refining Market Design', ch.2, pp 35-64, in *Electricity Reform in Europe: Towards a Single Energy Market*, eds. J-M. Glachant and F. Leveque, Cheltenham: Edward Elgar, ISBN 978 1 84720 973 3
- Roques, Fabien.A., David. M. Newbery and William J. Nuttall (2008) "Portfolio Optimization and Utilities' Investments in Liberalized Power Markets', Ch 11, pp221-48 in *Analytical Methods for Energy Diversity and Security,* M. Bazilien and F Roques (ed), Elsevier
- Hope, C. and D.M. Newbery (2008) 'Calculating the social cost of carbon', ch. 2, pp31-63 in *Delivering a Low Carbon Electricity System: Technologies, Economics and Policy*, M. Grubb, M., T. Jamasb and M. Pollitt, (eds.), CUP.
- Grubb, M.G. and D.M. Newbery, (2008) "Pricing carbon for electricity generation: national and international dimensions", ch. 11, pp278-313 in Delivering a Low Carbon Electricity System: Technologies, Economics and Policy, M. Grubb, T. Jamasb, M. Pollitt (eds.), CUP
- Grubb, M.G., N.Haj-Hasan and D.M. Newbery, (2008) "Accelerating innovation and strategic deployment in UK electricity: applications to renewable energy", ch. 13, pp333-360 in *Delivering a Low Carbon Electricity System: Technologies, Economics and Policy,* M. Grubb, T. Jamasb, M. Pollitt (eds.), CUP
- Newbery, D.M. (2007) 'Power sector reform, private investment and regional co-operation' chapter 6 in *South Asia – Regional Integration and Growth*, Washington, D.C.: World Bank Report 37858-SAS, pp 107-28, McMillan Press, India.
- Newbery, D.M. (2006) "Electricity Liberalization in Britain and the Evolution of Market Design", ch 4, pp109-144, in F.P. Sioshansi and W. Pfaffenberger (eds.) *Electricity Market Reform: An International Perspective*, Amsterdam: Elsevier,

ISBN13 978-0-08045-030-8

- Newbery, D.M. and T. McDaniel (2003) ‘Auctions and Trading In Energy Markets - An Economic Analysis’, Ch 10, pp195-234 in *CRI Regulatory Review2002/ 2003* P. Vass (ed.) (ISBN 1 85790 1142) Bath: Centre for the Study of Regulated Industries.

Official Working Papers not elsewhere listed

- Roques, Fabien A., Nuttall, William J. and Newbery, David M. (2006) 'Using probabilistic analysis to value power generation investments under uncertainty', EPRG 06/19

- Newbery, D.M. (2003) ‘The relationship between regulation and competition policy for network utilities’, Tokyo, Competition Policy Research Center, Fair Trade Commission of Japan, CPDP-5-E, December

Reports to National and International Organisations

- Newbery, D.M., G. Strbac , D. Pudjianto, P. Noël, Booz & Co. and LeighFisher, (2013) *Benefits Of An Integrated European Energy Market* Final report for DG ENER, July at http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf

- Strbac, G., R, Green, C.V. Konstantinidis, I. Konstantelos, R. Moreno, D.M. Newbery, M. Pollitt (2013) *Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery*, Ofgem, June at https://www.ofgem.gov.uk/sites/default/files/docs/2013/06/imperial_cambridge_itpr_report_0.pdf

- Newbery, D.M. **and G. Strbac (2011)** ***Physical and Financial Capacity Rights for Cross-Border Trade*****, prepared for DG-ENER under contract with Booz and Company London available at** http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2012_transmission.pdf

- Newbery, D.M. **(2011)** High level principles for guiding GB transmission charging and some of the practical problems of transition to an enduring regime, report for Ofgem, at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=93&refer=Networks/Trans/PT

- Newbery, D.M., D. Reiner, T. Jamasb, R. Steinberg, F. Toxvaerd, P. Noel (2009) “Carbon Capture & Storage (CCS): Analysis of Incentives and Rules in a European Repeated Game Situation” Report for DECC, available at http://decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/ccs/ccs.aspx

- Jamasb, T, K Neuhoff, D Newbery and M Pollitt (2005) *Long term framework for distribution access charges*, Report Prepared for and Commissioned by Ofgem
- Newbery, D.M. (2002) 'Issues and Options for Restructuring Electricity Supply Industries', CMI EP01 (available at http://ideas.repec.org/p/cam/camdae/0210.html and also at http://rru.worldbank.org/PapersLinks/Regulating-Electricity-Markets/)

ANNEX C LETTER OF INSTRUCTIONS

Our ref: LIZC\RIJR\02 3002 8238
Partner: Liza Carver
Direct line: +61 2 9258 5897
Email: liza.carver@ashurst.com

Ashurst Australia
Level 26
181 William Street
Melbourne VIC 3000
Australia

GPO Box 9938
Melbourne VIC 3001
Australia

Tel +61 3 9679 3000
Fax +61 3 9679 3111
DX 388 Melbourne
www.ashurst.com

ashurst

23 December 2014

Professor David Newbery
Chairman
Cambridge Economic Policy Associates
Queens House
55-56 Lincoln's Inn Fields
London WC2A 3LJ
United Kingdom

CONFIDENTIAL & PRIVILEGED

Dear David

Letter of engagement – Networks NSW – AER Draft Determination

Ausgrid, Endeavour Energy and Essential Energy (referred to collectively as **Networks NSW**) are distribution network service providers in New South Wales, Australia regulated by the Australian Energy Regulator (**AER**) under the National Electricity Law (**NEL**) and National Electricity Rules (**NER**).

The AER made a draft determination of the revenue allowances for Networks NSW on 27 November 2014. This letter confirms your engagement in relation to Networks NSW's response to that draft determination (**Response**).

Scope of engagement

You are engaged by us, on behalf of Networks NSW, for the purposes of the Response, to:

(a) provide economic analysis and advice;

(b) prepare a written expert report (or reports);

(c) appear as an expert witness for Networks NSW (if required); and

(d) undertake such other work as Ashurst Australia may instruct you as the Response progresses.

A document outlining a list of questions that we require you to address in your expert report is set out in **Attachment 1**. These questions may be refined and developed, and added to, as the Response progresses.

A document outlining the relevant background to the regulatory regime is included as **Attachment 2**.

Also **enclosed** is a copy of Practice Note CM7: Expert witnesses in proceedings in the Federal Court of Australia. Please ensure that your report complies with the requirements of Practice Note CM7, and also certify in your report that you have complied with Practice Note CM7.

Ashurst requires a draft version of the report by 2 January 2015, and a final report by 9 January 2015.

Remuneration

We will pay you on Networks NSW's behalf for time spent on this matter in accordance with the instructions of Networks NSW or Ashurst Australia, at the rates separately agreed between you and Networks NSW.

Confidentiality

Networks NSW requires you to agree to keep strictly confidential all Confidential Information disclosed to you during the course of your engagement in relation to the Response. This obligation survives the conclusion of your engagement under this letter.

You acknowledge that the Confidential Information will include information about the Response. You acknowledge that the Confidential Information is secret, confidential and of value to Networks NSW, and its unauthorised use or disclosure may significantly damage Networks NSW's business.

You agree that you must:

(a) keep the Confidential Information secret and confidential at all times;

(b) not disclose any Confidential Information to anyone except with Networks NSW's prior permission; and

(c) ensure that each person to whom you disclose Confidential Information with the prior permission of Networks NSW, including each member of your staff working with you in connection with this engagement, makes the same acknowledgment, agrees to comply with, and does comply with, (a) and (b) above.

In the event that you are required by a court or otherwise by law to disclose Confidential Information, you agree that you will inform Networks NSW of this fact as soon as is possible in advance of this disclosure.

Intellectual Property Rights

You agree:

(a) that Networks NSW retains all Intellectual Property Rights in any Materials which may be disclosed to you in the course of your engagement; and

(b) to transfer to Networks NSW all Intellectual Property Rights in any Materials created by you in the course of your engagement.

Return of Confidential Documents

On request of Networks NSW, you must:

(a) return to Networks NSW any documents or other materials containing Confidential Information, or, if they are in electronic form, erase or destroy them and provide evidence of erasure or destruction to the satisfaction of Networks NSW; and

(b) provide to Networks NSW or destroy any materials created by you in connection with this engagement that contain Confidential Information, or, if they are in electronic form, erase or destroy them and provide evidence of erasure or destruction to the satisfaction of Networks NSW.

Interpretation

In this letter:

(a) Networks NSW means each Networks NSW business and each of their related bodies corporate.

(b) **Confidential Information** includes all information in any form or medium relating to Networks NSW, which is disclosed to you by Networks NSW or its officers, employees, advisers or agents, but does not include any information which you can show:

(i) is in the public domain, otherwise than as a result of a breach of the contents of this letter; or

(ii) is already known to you prior to the disclosure or which is subsequently known to you as a result of disclosure by another source which was not, to the best of your knowledge, subject to any agreement for confidentiality.

(c) **Intellectual Property Rights** means all present and future rights conferred by statute, common law or equity in or in relation to copyright, trade marks, designs, patents, circuit layouts, plant varieties, business and domain names, inventions and confidential information, and other results of intellectual activity in the industrial, commercial, scientific, literary or artistic fields whether or not registrable, registered or patentable. These rights include:

(i) all rights in all applications to register these rights;

(ii) all renewals and extensions of these rights; and

(iii) all rights in the nature of these rights, such as moral rights.

(d) **Materials** means works, ideas, concepts, designs, inventions, developments, improvements, systems or other material or information, created, made or discovered by you (either alone or with others and whether before or after the date of this document) in the course of your employment or as a result of using the resources of Networks NSW or in any way relating to any business of Networks NSW.

Please indicate your acceptance of these terms by signing the enclosed duplicate of this letter in the space provided, and then returning it to us.

Yours faithfully

Ashurst Australia

Ashurst Australia

I accept the terms contained in this letter.

D Newbery

Professor David Newbery

23 December 2014

Date

232502197.02

ashurst

ATTACHMENT 1

DRAFT LIST OF TOPICS REQUIRED TO BE ADDRESSED

The National Electricity Objective (**NEO**) set out in section 7 of the National Electricity Law is:

> *"The objective of this Law is 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."*

Section 16 of the National Electricity Law requires that the AER must, in performing or exercising an AER economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the NEO. The making of a distribution determination is an AER economic regulatory function or power. Further, section 16(1)(d) requires that if the AER is making a distribution determination and there are two or more possible reviewable regulatory decisions that will or are likely to contribute to the achievement of the NEO, the AER is required to make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.

Also of particular relevance are the revenue and pricing principles set out in section 7A of the National Electricity Law. Relevantly, section 16(2)(a) provides that the AER must take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination relating to direct control services.

The revenue and pricing principles are set out in section 7A of the National Electricity Law and provide, amongst other things that: (a) a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services; and complying with a regulatory obligation or requirement or making a regulatory payment; (b) 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; (c) a price or charge for the provision of direct control network services 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; (d) 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 network or a transmission system with which the operator provides direct control network services; and (e) 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.

Your report should address the following topics in the context of the NEO and the revenue and pricing principles:

General observations on the regulatory framework and its objective

(a) The economic basis and purpose for the regulation of monopoly electricity distributors.

(b) What do you understand the NEO to mean?

(c) What would be the key design features of an economic regulatory regime that is designed to achieve the NEO?

(d) Pursuant to clause 6.4.3 of the NER, the annual revenue requirement for a distribution network service provider for each year of a regulatory control period must be determined using a building block approach, under which the building blocks are:

(i) indexation of the regulatory asset base;

(ii) a return on capital for that year;

(iii) the depreciation for that year;

(iv) the estimated cost of corporate income tax of the distribution network service provider for that year;

(v) the revenue increments or decrements (if any) for that year arising from the application of any relevant incentive scheme;

(vi) the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period;

(vii) the revenue decrements (if any) for that year arising from the use of assets that provide standard control service to provider certain other services; and

(viii) the forecast operating expenditure for that year.

In your view, and as a general matter without considering the specific circumstances of a particular network, is a correct application of the building block framework to determining the annual revenue requirement for direct control services likely or not to contribute to the achievement of the NEO? If so, how? If not, why not?

(e) To the extent you consider in response to (d) that the correct application of the building block framework is likely to contribute to the achievement of the NEO, if there is a material error in the application of the framework what are the likely consequences for the achievement of the NEO or the purpose of the economic regulation of monopoly electricity distributors referred to above?

(f) How, if at all, the appropriate regulation of monopoly electricity distributors takes into account the actual financial position of the regulated entity.

Specific observations on the regulatory framework and its objective in the context of the achievement of efficiencies

(a) To the extent costs are forecast to be incurred in a regulatory control period (such as redundancy payments) which are associated with the restructuring of a business undertaken to reduce costs in the long-run, what considerations are relevant to the regulatory treatment of such costs, including in the context of a regime that has as its objective one such as the NEO?

(b) Review and comment on Attachment 7 to the draft determination. Without limiting the passages to which you should have regard in undertaking your review, we draw attention to the following passages:

(i) the following extract from the AER's draft determination which appears on page 7-42 of Attachment 7 to the draft determination:

> "The NSW service providers do not disagree with making efficiency adjustments. Each of their regulatory proposals recognises a need to move towards a more efficient cost base. However, the service providers have proposed incremental adjustments to remove

inefficiency and have sought to recover some of the costs of these efficiency adjustments. This approach is inconsistent with the requirement for forecasts of expenditure to reasonably reflect the prudent and efficient costs of achieving the opex objectives. Further, under this approach consumers would bear not only the costs of removing inefficiencies but fund the inefficiencies themselves.

Also, the NSW service providers have, in our view, taken a flawed approach to identifying inefficiency because their approach does not incorporate top down benchmarking. It is necessary to consider the efficiency of providing services overall rather than the efficiency of specific activities. The NSW service providers have proposed incremental efficiency adjustments that apply to specific activities. This approach focuses on certain aspects of performance in isolation, which ignores the trade-offs of delivering different output combinations. Under this approach, a service provider could offset the savings it identifies for one output by increasing costs for another." (footnote omitted)

(ii) on page 7-16, the paragraph commencing "As outlined in our Guideline";

(iii) pages 7-26 and 7-27;

(iv) page 7-33;

(v) section A.2.5 ("Implementing efficiency improvements") (pp 7-51 to 7-54); and

(vi) pages 7-166 and 7-167 (the section under the heading "Cost base restructure and efficiency program").

ATTACHMENT 2

BACKGROUND ON REGULATORY REGIME APPLYING TO ELECTRICITY DISTRIBUTION NETWORK SERVICE PROVIDERS IN NEW SOUTH WALES

1. INTRODUCTION

Networks New South Wales (**NNSW**) are the three *distribution network service providers* (**DNSPs**) in NSW – Ausgrid, Endeavour Energy and Essential Energy – regulated under the National Electricity Law (**NEL**) and Chapter 6 of the National Electricity Rules (**NER**). As such, the three DNSPs were required to, and did submit, in May this year, regulatory proposals to the Australian Energy Regulator (**AER**) for the determination of, among other things, their annual revenue requirements for the period 1 July 2014 to 30 June 2019 (**Proposals**).

Part C of Chapter 6 of the NER sets out rules for the economic regulation of standard control services provided by DNSPs. This regime requires the AER to determine the revenue allowed to be earned by NNSW for distribution services during each regulatory year, in accordance with the post-tax revenue model, described in Part C of Chapter 6 of the NER for each regulatory control period. The process for making a distribution determination is set out in Part E of Chapter 6 of the NER.

2. DISTRIBUTION DETERMINATIONS

Under the NER, DNSPs must provide direct control services (which are divided into standard control services and alternative control services) and negotiated distribution services on terms and conditions of access as determined under Chapters 4, 5, 6 and 7 of the NER (clause 6.1.3 of the NER). Relevantly, Chapter 6 of the NER regulates:

(a) for standard control services, the annual revenue requirements NNSW may earn for the provision of standard control services for which the AER must make a revenue determination (clause 6.3.2 of the NER); and

(b) for negotiated distribution services, the requirements that are to be complied with in respect of the preparation, replacement, application or operation of NNSW's negotiating frameworks and the Negotiated Distribution Service Criteria (clauses 6.7.3 and 6.7.4 of the NER).

The making of a distribution determination is an economic regulatory function of the AER. As an economic regulatory function, section 16(1) of the NEL requires the AER to perform or exercise its function "in a manner that will or is likely to contribute to the achievement of the national electricity objective" set out in section 7 of the NEL being:

> *"The objective of this Law is 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."*

In addition, if there are two or more possible decisions that will or are likely to contribute to the achievement of the national electricity objective, section 16(1)(d) of the NEL requires the AER to make a decision that it is satisfied will, or is likely to, contribute to the achievement of the national electricity objective to the greatest degree.

Further, when exercising a discretion in making those parts of a distribution determination relating to direct control network services, the AER must also take into account the revenue and pricing principles set out in section 7A of the NEL. Most relevantly:

"(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—

(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.

...

(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."

3. BUILDING BLOCK DETERMINATION

As part of the distribution determination process, the AER must make a *building block determination*, and NNSW must submit a *building block proposal* in respect of each DNSP (clause 6.3.1 of the NER). Each building block proposal must be consistent with the post-tax revenue model, which is published by the AER.

Under clause 6.3.2 of the NER, a building block determination must specify:

(a) the DNSP's "annual revenue requirement" for each regulatory year of the regulatory control period;

(b) appropriate methods for the indexation of the regulatory asset base;

(c) how any relevant incentive scheme is to apply to the DNSP;

(d) the commencement and length of the regulatory control period; and

(e) any other amounts, values or inputs on which the which the building block determination is based (differentiating between those contained in, or inferred from, the Distribution Network Service Provider's building block proposal and those based on the AER's own estimates or assumptions).

The post-tax revenue model required to be published by the AER sets out the manner in which the DNSP's annual revenue requirement for each regulatory year of a regulatory control period is to be calculated (clause 6.4.2(a) of the NER). The contents of the post-tax revenue model must include (but need not be limited to) (clause 6.4.2(b) of the NER):

(a) a method that the AER determines is likely to result in the best estimates of expected inflation;

(b) the timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks referred to in clause 6.4.3;

(c) the manner in which working capital is to be treated; and

(d) the manner in which the estimated cost of corporate income tax is to be calculated.

The building blocks that comprise the building block determination are set out in clauses 6.4.3 and 6.5 of the NER. These include the:

(a) regulatory asset base;

(b) return on capital (including return on debt and return on equity);

(c) depreciation;

(d) corporate income tax;

(e) revenue increments or detriments arising from any:

  (i) efficiency benefits sharing scheme;

  (ii) capital expenditure sharing scheme;

  (iii) service target performance incentive scheme;

  (iv) demand management and embedded generation connection incentive scheme; and

  (v) small-scale incentive scheme;

(f) other revenue increments or detriments (if any) arising from the application of a control mechanism in the previous regulatory control period;

(g) revenue decrements (if any) arising from the use of assets that provide standard control services to provide certain other services; and

(h) forecast operating expenditure.

The following sections focus on the return on capital and operating costs component of the building blocks proposals and determinations as these are the components relevant for the topics set out in Attachment 1.

4. RETURN ON CAPITAL

The return on capital for each year of the regulatory control period is calculated by multiplying the regulatory asset base at the beginning of that year by the allowed rate of return calculated in accordance with clause 6.5.2 of the NER.

Clause 6.5.2 requires the AER to determine the allowed rate of return such that it achieves the allowed rate of return objective. Clause 6.5.2(c) sets out the allowed rate of return objective as follows:

> *"The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of*

a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective)."

Clause 6.5.2(d) of the NER requires the allowed rate of return to be:

(a) a weighted average of the return on equity for the regulatory control period and the return on debt for the relevant year of that regulatory control period; and

(b) determined on a nominal vanilla basis that is consistent with the calculation of imputation credits.

In addition, when determining the allowed rate of return, clause 6.5.2(e) requires the AER to have regard to the following:

(a) relevant estimation methods, financial models, market data and other evidence;

(b) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and

(c) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

Specific rules are set out in the NER for the calculation of the return on equity and the return on debt. Both the return on equity and the return on debt <u>must be estimated such that they contribute to the allowed rate of return objective</u> (clauses 6.5.2(f) and (h) of the NER).

For completeness, clause 6.5.2(m) of the NER also requires the AER to publish Rate of Return Guidelines (**ROR Guidelines**). The ROR Guidelines must set out (clause 6.5.2(n) of the NER):

(a) the methodologies that the AER proposes to use in estimating the allowed rate of return, including how those methodologies are proposed to result in a determination of the return on equity and return on debt in a way consistent with the rate of return objective; and

(b) the estimation methods, financial models, market data and other evidence the AER proposes to take into account in estimating the return on equity, return on debt and the value of imputation credits.

Under clause 6.2.8(c) of the NER, the AER is not bound to apply the ROR Guidelines when making a distribution determination. However, if the AER makes a distribution determination that is not in accordance with the ROR Guidelines, the AER must state in its reasons for the distribution determination the reasons for departing from the ROR Guidelines. Similarly, clause S6.1.3(9) of the NER requires NNSW to identify any departures from the ROR Guidelines and the reasons for those departures in its Proposals.

4.1. RETURN ON DEBT REQUIREMENTS

In addition to the overall requirement for the return on debt to be estimated such that it achieves the rate of return objective:

(a) the AER may estimate the return of debt so that it is the same in each year of the regulatory control period or so that it is different in each year of the regulatory control period (clause 6.5.2(i) of the NER);

(b) subject to the rate of return objective, the methodology used to estimate the return on debt may be designed to result in a return on debt reflecting (clause 6.5.2(j) of the NER):

> *"(1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period;*
>
> *(2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or*
>
> *(3) some combination of the returns referred to in subparagraphs (1) and (2)"*; and

(c) the AER must have regard to the following factors when estimating the return on debt (clause 6.5.2(k) of the NER):

> *"(1) the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;*
>
> *(2) the interrelationship between the return on equity and the return on debt;*
>
> *(3) the incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and*
>
> *(4) any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next".*

4.2. RETURN ON EQUITY REQUIREMENTS

The NER set out two rules for the calculation of the return on equity:

(a) as with the estimation of return on debt, Chapter 6 of the NER provides that the return on equity must be estimated such that it contributes to the allowed rate of return objective (clauses 6.5.2(f) of the NER); and

(b) in so estimating the return on equity, the AER must also have regard to the "prevailing conditions in the market for equity funds" (clauses 6.5.2(f) and (g) of the NER).

5. OPERATING EXPENDITURE

A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the DNSP considers is required in order to achieve the operating expenditure objectives, being:

(a) meet or manage the expected demand for standard control services over that period;

(b) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(c) to the extent that there is no applicable regulatory obligation or requirement in relation to (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent, (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(d) maintain the safety of the distribution system through the supply of standard control services.

The AER is required to accept the forecast of required operating expenditure of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflect each of the operating expenditure criteria, being:

"(1) the efficient costs of achieving the operating expenditure objectives; and

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives."

In deciding whether or not it is satisfied that the forecast of required operating expenditure proposed by a distribution network service provider reasonably reflects the operating expenditure criteria in clause 6.5.6(c) of the NER, the AER must have regard to the following factors (clause 6.5.6(e) of the NER, referred to as **operating expenditure factors**):

"...

(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;

(5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;

(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;

(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;

(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);

(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);

(12) *any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor."*

5. CAPITAL EXPENDITURE

A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the DNSP considers is required in order to achieve the capital expenditure objectives, being:

(e) meet or manage the expected demand for standard control services over that period;

(f) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(g) to the extent that there is no applicable regulatory obligation or requirement in relation to (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent, (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(h) maintain the safety of the distribution system through the supply of standard control services.

The AER is required to accept the forecast of required capital expenditure of a DNSP that is included in a building block proposal if the AER is satisfied that the total of forecast capital expenditure for the regulatory control period reasonably reflects each of the following criteria, being the **capital expenditure criteria**:

"(1) *the efficient costs of achieving the capital expenditure objectives; and*

(2) *the costs that a prudent operator would require to achieve the capital expenditure objectives; and*

(3) *a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives."*

In deciding whether or not it is satisfied that the forecast of required capital expenditure proposed by a DNSP reasonably reflects the capital expenditure criteria in clause 6.5.6(c) of the NER, the AER must have regard to the following factors (clause 6.5.6(e) of the NER, referred to as **capital expenditure factors**):

"...

(4) *the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;*

(5) *the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*

(5A) *the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;*

(6) *the relative prices of operating and capital inputs;*

(7) *the substitution possibilities between operating and capital expenditure;*

(8) *whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4;*

(9) *the extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;*

(9A) *whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);*

(10) *the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and*

(11) *any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);*

(12) *any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor."*

INDEX

TAB	DOCUMENT	DATE
Legislation and Rules		
	National Electricity Law	19 December 2013
	Chapter 6 of the NER	1 October 2014
	Chapter 10 of the NER	1 October 2014
	Draft decision – Overview – Ausgrid	27 November 2014
	Draft decision – Overview – Endeavour	27 November 2014
	Draft decision – Overview – Essential	27 November 2014
	Attachment 7 to Ausgrid's draft decision (Operating expenditure)	27 November 2014

ANNEX D AMENDMENT TO LETTER OF INSTRUCTIONS

Our ref: LIZC\RIJR\02 3002 8238
Partner: Liza Carver
Direct line: +61 2 9258 5897
Email: liza.carver@ashurst.com
Contact: Richard Robinson, Senior Associate
Direct line: +61 7 3259 7219
Email: richard.robinson@ashurst.com

Ashurst Australia
Level 36, Grosvenor Place
225 George Street
Sydney NSW 2000
Australia

GPO Box 9938
Sydney NSW 2001
Australia

Tel +61 2 9258 6000
Fax +61 2 9258 6999
DX 388 Sydney
www.ashurst.com

16 January 2015

BY EMAIL
CONFIDENTIAL & PRIVILEGED

David Newbery
Chairman
Cambridge Economic Policy Associates
Queens House
55-56 Lincoln's Inn Fields
London WC2A 3LJ
United Kingdom

Dear David

Networks NSW – AER Draft Determination – Amendment to list of questions

The letter of engagement dated 17 December 2014 included a list of questions in Attachment 1 that may be refined, developed and added to as your response develops. As discussed, we would like to include an additional question for you to consider:

> *"Please comment on the AER's approach to benchmarking"*

We have included the amended list of questions as attachment 1.

Please let us know if you would like to discuss.

Yours faithfully

Ashurst Australia

Ashurst Australia

AUSTRALIA BELGIUM CHINA FRANCE GERMANY HONG KONG SAR INDONESIA (ASSOCIATED OFFICE) ITALY JAPAN PAPUA NEW GUINEA SAUDI ARABIA SINGAPORE SPAIN SWEDEN UNITED ARAB EMIRATES UNITED KINGDOM UNITED STATES OF AMERICA

Ashurst Australia (ABN 75 304 286 095) is a general partnership constituted under the laws of the Australian Capital Territory and is part of the Ashurst Group. The Ashurst Group has an office in each of the places listed above.
233378727.01

ATTACHMENT 1

LIST OF TOPICS REQUIRED TO BE ADDRESSED

The National Electricity Objective (**NEO**) set out in section 7 of the National Electricity Law is:

> *"The objective of this Law is 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."*

Section 16 of the National Electricity Law requires that the AER must, in performing or exercising an AER economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the NEO. The making of a distribution determination is an AER economic regulatory function or power. Further, section 16(1)(d) requires that if the AER is making a distribution determination and there are two or more possible reviewable regulatory decisions that will or are likely to contribute to the achievement of the NEO, the AER is required to make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.

Also of particular relevance are the revenue and pricing principles set out in section 7A of the National Electricity Law. Relevantly, section 16(2)(a) provides that the AER must take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination relating to direct control services.

The revenue and pricing principles are set out in section 7A of the National Electricity Law and provide, amongst other things that: (a) a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services; and complying with a regulatory obligation or requirement or making a regulatory payment; (b) 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; (c) a price or charge for the provision of direct control network services 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; (d) 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 network or a transmission system with which the operator provides direct control network services; and (e) 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.

Your report should address the following topics in the context of the NEO and the revenue and pricing principles:

General observations on the regulatory framework and its objective

(a) The economic basis and purpose for the regulation of monopoly electricity distributors.

(b) What do you understand the NEO to mean?

(c) What would be the key design features of an economic regulatory regime that is designed to achieve the NEO?

(d) Pursuant to clause 6.4.3 of the NER, the annual revenue requirement for a distribution network service provider for each year of a regulatory control period must be determined using a building block approach, under which the building blocks are:

(i) indexation of the regulatory asset base;

(ii) a return on capital for that year;

(iii) the depreciation for that year;

(iv) the estimated cost of corporate income tax of the distribution network service provider for that year;

(v) the revenue increments or decrements (if any) for that year arising from the application of any relevant incentive scheme;

(vi) the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period;

(vii) the revenue decrements (if any) for that year arising from the use of assets that provide standard control service to provider certain other services; and

(viii) the forecast operating expenditure for that year.

In your view, and as a general matter without considering the specific circumstances of a particular network, is a correct application of the building block framework to determining the annual revenue requirement for direct control services likely or not to contribute to the achievement of the NEO? If so, how? If not, why not?

(e) To the extent you consider in response to (d) that the correct application of the building block framework is likely to contribute to the achievement of the NEO, if there is a material error in the application of the framework what are the likely consequences for the achievement of the NEO or the purpose of the economic regulation of monopoly electricity distributors referred to above?

(f) How, if at all, the appropriate regulation of monopoly electricity distributors takes into account the actual financial position of the regulated entity.

(g) Please comment on the AER's approach to benchmarking.

Specific observations on the regulatory framework and its objective in the context of the achievement of efficiencies

(a) To the extent costs are forecast to be incurred in a regulatory control period (such as redundancy payments) which are associated with the restructuring of a business undertaken to reduce costs in the long-run, what considerations are relevant to the regulatory treatment of such costs, including in the context of a regime that has as its objective one such as the NEO?

(b) Review and comment on Attachment 7 to the draft determination. Without limiting the passages to which you should have regard in undertaking your review, we draw attention to the following passages:

(i) the following extract from the AER's draft determination which appears on page 7-42 of Attachment 7 to the draft determination:

"The NSW service providers do not disagree with making efficiency adjustments. Each of their regulatory proposals recognises a need to move towards a more efficient cost base. However, the service providers have proposed incremental adjustments to remove inefficiency and have sought to recover some of the costs of these efficiency adjustments. This approach is inconsistent with the requirement for forecasts of expenditure to reasonably reflect the prudent and efficient costs of achieving the opex objectives. Further, under this approach consumers would bear not only the costs of removing inefficiencies but fund the inefficiencies themselves.

Also, the NSW service providers have, in our view, taken a flawed approach to identifying inefficiency because their approach does not incorporate top down benchmarking. It is necessary to consider the efficiency of providing services overall rather than the efficiency of specific activities. The NSW service providers have proposed incremental efficiency adjustments that apply to specific activities. This approach focuses on certain aspects of performance in isolation, which ignores the trade-offs of delivering different output combinations. Under this approach, a service provider could offset the savings it identifies for one output by increasing costs for another." (footnote omitted)

(ii) on page 7-16, the paragraph commencing "As outlined in our Guideline";

(iii) pages 7-26 and 7-27;

(iv) page 7-33;

(v) section A.2.5 ("Implementing efficiency improvements") (pp 7-51 to 7-54); and

(vi) pages 7-166 and 7-167 (the section under the heading "Cost base restructure and efficiency program").

ANNEX E DOCUMENTS I HAVE BEEN INSTRUCTED TO CONSIDER

TAB	DOCUMENT	DATE
Legislation and Rules		
	National Electricity Law	19 December 2013
	Chapter 6 of the NER	1 October 2014
	Chapter 10 of the NER	1 October 2014
	Draft decision – Overview – Ausgrid	27 November 2014
	Draft decision – Overview – Endeavour	27 November 2014
	Draft decision – Overview – Essential	27 November 2014
	Attachment 7 to Ausgrid's draft decision (Operating expenditure)	27 November 2014