16 April 2012

Mr John Pierce
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
Sydney NSW 2000

via website: submissions@aemc.gov.au

Dear John

Response to AEMC Directions Paper – Economic Regulation of Network Service Providers

Please find attached the ENA submission to the AEMC Directions Paper (dated 2 March 2012) on the Economic Regulation of Network Service Providers.

I would highlight two key points in our submission:

- Complex matters have been raised in the Directions Paper, in particular, the WACC framework, debt estimation and capital expenditure incentives. The submission explains why these matters warrant separate processes to consider design and implementation questions more thoroughly than possible in a rules change process.

- The Directions Paper seeks evidence on the drivers of increased prices, and whether deficiencies in the Rules have contributed systemically to those increases. In response, ENA asked NERA Economic Consulting to provide a rigorous analysis of network prices changes following the most recent regulatory determinations. The report (Attachment A) finds that the increases were driven by changes in external circumstances, which have been examined and acknowledged by the AER, rather than being a product of the Rules.

A further report (Attachment D – Joint Report – Current DRP Benchmark and its Measurement) will be provided to the AEMC later this week.

The ENA recognises the work put into the Rule change by the AEMC and appreciates the opportunity to contribute to its development.

If you have any questions please contact Garth Crawford on 02 6272 1507 or alternatively we would be pleased to provide the Commissioners with a comprehensive briefing on the ENA submission at their earliest convenience.

Yours sincerely

Malcolm Roberts
Chief Executive

Response to Directions Paper

Proposed Energy Rules Changes:

Economic Regulation of Network Service Providers

Calculation of Return on Debt for Electricity Network Businesses

AEMC Reference: ERC0134

1. Overview

Energy Network Association (ENA) members welcome the Australian Energy Market Commission's (AEMC) Directions Paper relating to proposals made by the Australian Energy Regulator (AER) and the Energy Users Rule Change Committee (EURCC). This stage of the rule change process is an important avenue for exploring and testing possible improvements to regulatory frameworks and practice in the Australian energy sector based on evidence from the experience to date.

The AEMC has asked a set of questions and identified a number of specific areas of detailed inquiry, in particular around underlying drivers for network price increases. The ENA has commissioned specific work directed at addressing the causes of network prices increases, broken down to a State and Territory basis. This work finds that there are a range of factors contributing to network prices increases, which vary across networks based on their individual circumstances, and demand conditions. There are also a number of common contributing factors including investment to meet peak demand, replace ageing assets, and meeting higher debt financing costs prevailing in capital markets since the Global Financial Crisis. Critically, there is no evidence that the regulatory rules have contributed to network pricing increases, as opposed to changes in the costs faced by networks.

The network sector supports a robust regulatory framework that provides confidence to the community that proposed network expenditures are efficient, well-evidenced, and able to be tested by a regulatory body in possession of appropriate powers and resources. The Commission has identified a range of wider policy issues which, in the ENA's view, relate to re-establishing confidence in the regulatory framework that are beyond the scope of the current review. The ENA acknowledges this and will be advocating a range of proposals in appropriate policy and review processes being undertaken by Standing Committee on Energy and Resources and the Commission.

The ENA supports the view that it is important that regulatory accountability is in place to correct for any regulatory errors that may arise in respect the appropriate rate of return. The lack of such accountability would be a material backwards step for a regulatory regime seeking to promote ongoing investment in sunk long-lived assets. It is noted that the Standing Committee on Energy and Resources' review of limited merits review has commenced consideration of these critical issues.

Scope and complexity of the issues

As industry has sought to develop its own positions and understandings on a limited number of rule change issues it has become clear that they involve significantly greater complexity than initially appreciated. Based on this appreciation, and evidence from external expert works examining the issues (previously provided to the Commission in the initial consultation process), the ENA considers that if a number of more comprehensive rule changes were to be developed and pursued in these areas they should be taken forward in dedicated separate processes. This would have the advantage of these processes not being subject to the time constraints of the rule change process. These matters include amendments to the WACC framework for gas networks, the measurement of the cost of debt, and capital expenditure incentive schemes. The ENA is concerned that the current process envisaged by the AEMC for dealing with these aspects of the AER and EURCC rule change proposals may not provide adequate time for full deliberation of the issues. This may result in sub-optimal amendments to the Rules and the need for further review of the Rules relating to these matters after only a short period.

In particular, the development of a detailed framework for estimating the rate of return to apply across the electricity and gas frameworks appears to be a substantial analytical and regulatory design task. Quality outcomes may be best achieved outside of the relatively tight time constraints of the current rule determination process. Similarly, any exploration and development of a historical trailing average approach to inform cost of debt estimates could benefit from a less constrained review process. This would provide time for full consideration of the methodological and implementation issues that would need to be considered prior to a rule in this area being made.

Operating and capital expenditure forecasts

A balanced examination of the capital and operating forecasting framework and incentives established in the *National Electricity Rules* reveals a regime which was the subject of careful design and consideration by a number of parties. This included the AEMC, Ministerial Council on Energy (MCE) policy makers, and the MCE Expert Panel on Energy Access Pricing. ENA members consider that the framework for forecasting, and the incentives it creates to make well-founded regulatory proposals, is based on sound principles of regulatory design. Furthermore, a regime that does not place fundamental weight on a network businesses proposal would fail to effectively leverage the network businesses' core commercial and technical expertise and significantly weaken the operation of incentive-based regulation.

Capital expenditure incentive frameworks

The network sector supports the use of incentive-based mechanisms to promote continuous, effective and stable financial incentives for efficient expenditure. To this end, the network sector considers that the development and implementation of a symmetrical, principles-based capital expenditure incentive mechanism would be desirable. This should be feasible, with appropriate adaptions, across both electricity transmission and distribution rules. This approach is far preferable to a reversion of the regulatory framework towards provision of *ex post* prudence assessment processes. Such assessments involve intractable design and implementation issues surrounding later decision-makers with information unavailable to the network business being able to retrospectively strand prudent investments. The disadvantages of *ex post* prudency tests include a capacity to distort efficient investment, and increased regulatory risk to providers of capital.

Appropriate rate of return framework

In relation to rate of return frameworks, the network sector considers that an optimum balancing of sound regulatory principles supports the adoption of an approach based on that contained in Chapter 6, applying to electricity distribution. However, experience to date, and addressing all the principles proposed by the AEMC, requires some targeted modification of the Chapter 6 arrangements. The regime would be improved by a setting out of the overall objective and nature of the cost of capital estimate being sought, allowing estimates flowing from the application or departure from a regular Statement of Cost of Capital to be 'tested' against an overall WACC principle on a consistent basis. This would improve certainty around the operation of the 'departure criteria' for businesses, users and the regulator alike. Removal of the Chapter 6A approach, in favour of revised Chapter 6 arrangements, would be a positive outcome of the rule change process, given the practical deficiencies that have arisen in applying Chapter 6A.

The network sector considers a benchmark approach to cost of debt estimation must remain an underpinning feature of the regulatory framework. In this respect, the currently specified benchmark for determining the debt risk premium in the *National Electricity Rules* remains appropriate.

Propositions that the current benchmark systematically overstates prevailing conditions in the market and create a 'windfall' gain to regulated entities are not consistent with a full assessment of the financing opportunities and risks of these entities. Since the Commission's previous *Consultation Paper*, there have a range of regulatory and appeal processes which have demonstrated that the existing clauses governing the estimation of the cost of debt are workable. The ENA considers that the issues that have arisen to date are implementation issues within the remit of the AER to address. Specifically, the AER should immediately commence a process, in consultation with stakeholders, to address these issues. This would be consistent with recommendations by the Australian Competition Tribunal on this matter. This is to be preferred over approaches adopted by a number of state-based regulators that fail to adequately reflect key elements of the benchmark they purport to measure.

Regulatory processes

The ENA considers targeted revisions to the regulatory review process itself have the potential to both promote more efficient and timely regulatory decision-making, reduce unnecessary complexity in the initial stage of the review process, and enhance the capacity of consumer and other bodies to effectively participate. These revisions also need to ensure consistency with the standards of procedural fairness and ensure that they do not undermine the pricing and revenue principles set out in the National Electricity Law. Specifically these recognise the need for businesses to recover at least the efficient costs of delivering sunk capital investments, and finance new long-lived infrastructure assets. Suggestions include the potential to streamline elements of the regulatory process where key parties consider no material issues are in contention.

To this end, to assist the AEMC in developing detailed draft rules around changes to the regulatory determination process, the ENA proposes the formation of a collaborative working group between network businesses, the AER and other interested stakeholders, to identify feasible technical improvements based on the experiences of both parties through regulatory reviews to date.

2. Background and approach

This submission has been developed through close consultation with the ENA members, which are energy distribution and transmission network businesses operating through Australia. It represents the agreed policy perspectives of the networks sector as a whole based on its collective experience under existing national energy frameworks.

The submission is largely structured in accordance to questions raised in the AEMC's *Directions Paper* published on 2 March 2012 in relation to the AER and EURCC rule change proposals. The *Directions Paper* invited stakeholders to provide commentary around specific questions and addition to providing a broad response on the issues under consideration. Each section provides an outline of industry views on the relevant issues and then answers to the consultation questions posed.

The remainder of the submission is structured as follows:

Section 3 discusses network businesses view on the high-level policy context for the conduct of the review (p.3)

Section 4 provides industry responses to the Directions Paper in the areas of capital and operating forecasts and incentives (p.8)

Section 5 discusses proposed amendments to the capital and operating expenditure factors (p.38)

Section 6 sets out industry views on an appropriate rate of return framework (p.43)

Section 7 outlines network businesses responses to proposed changes in relation to regulatory process (p.59)

The submission should be read together with the attached Expert reports that provide supportive evidence on major areas of the proposed rule changes:

Attachment A - NERA Economic Consulting Report - Analysis of Key Drivers of Network Price Changes

Attachment B - NERA Economic Consulting Report – Rising Electricity Prices and Network Productivity: a Critique

Attachment C - Joint Report – Capital and Operating Expenditure – Response to the AEMC Directions Paper

Attachment D - Joint Report - Current DRP Benchmark and its Measurement (to be provided separately)

Attachment E - Joint Report - Trailing Average Approaches to the Cost of Debt Allowance

Attachment F - Farrier Swier Consulting Report – Assessment of Proposed Changes to Regulatory Process and Practice Rules

3. Policy context for rule change process

3.1 Wider policy context for the rule change process

The energy network sector has a strong interest in a regulatory framework which enjoys the confidence of the community. It is important that customers, service providers, providers of capital and policy makers each have confidence that the regulatory regime will promote stable, clearly justifiable pricing outcomes which maximise economic efficiency for the long term benefit of the community. In the view of energy networks there are a number of requirements to promote this confidence, including:

- an incentive based regulatory framework to drive efficiency in operating and capital costs
- incentives for regulated businesses to forecast accurately, which was an explicit regulatory design objective of the Chapter 6A framework and the ‘fit for purpose’ model more generally
- the capacity for the regulator to apply robust and meaningful ‘tests’ to the efficiency of regulated businesses’ proposals and performance, including benchmarking approaches

Trends in the shape of network investment over the next decade reinforce these fundamental requirements of the regulatory system. These trends include the increasingly pervasive integration of digital technologies into network assets and operations and a steady movement to a bi-directional grid incorporating an evolving range of embedded generation and demand management technologies and options. Individual networks responses to these forces mean that it is increasingly useful to see networks’ regulatory proposals as tailored ‘price-service packages’ requiring close engagement between the priorities and willingness to pay of network users, and the network business. In this regard, rule changes should be framed with a view to ensuring accountability continues to clearly sit with the network service provider to deliver agreed reliability and service standard outcomes, and bear appropriate incentives and penalties.

The ENA also considers that there are a number of important channels beyond the current rule change process which provide further means of building community confidence in the regulatory process. These include:

- the provision of a stronger resources and capability to enable the AER to more probatively analyse, assess and weigh information provided to the AER through existing regulatory information powers;
- a set of stronger, well resourced and nationally-focused consumer advocacy arrangements to play a key ‘testing’ and ‘contradictor’ role in the regulatory process; and
- movement to reliability standard setting processes which better integrate publically transparent, and improved measures of consumer willingness to pay for varying service levels.

Energy networks aim to support and develop proposals in these areas to advance in the wider energy market policy processes administered by the Standing Council on Energy and Resources.

3.2 Timeline and process

The network sector has sought to provide as comprehensive a response to the issues raised in the Directions Paper as feasible in the consultation process to date, and are appreciative of the range of complex issues subject to the Commission’s considerations prior to a draft rule determination in July 2012. The ENA has previously raised concerns as to the ability for all of the issues raised in the AER’s Rule change proposal to be dealt with appropriately in the indicative timeframe set by the AEMC.

The network sector believes that successful development and implementation of proposals in a discrete number of areas will require further substantive consideration to be given to the issues raised. The network sector would be concerned about any amendments in a number of areas prior to dedicated consideration of some of the design and implementation issues raised in these proposals. Amendments made to the Rules that have not been the subject of complete analysis carry a high risk of both resulting in rules that may operate in a manner that is contrary to the long-term interests of consumers as well as rules that may need to be the subject of a further rule change process after a short period of time. The areas that in ENA's view warrant further dedicated specific focus outside of the current rule change timetable are:

- **WACC framework** – while the network industry consider that harmonisation of the Chapter 6A with a modified form of the Chapter 6 WACC frameworks is achievable and desirable in the context of the rule change timetable, the design and integration of a cross industry framework involving substantive amendments to the National Gas Rule raises more complex design issues better addressed in a separate process if the AEMC considers the required threshold has been reached which justified substantially altered gas arrangements;

- **Cost of debt** – The design of a historical trailing index approach, insofar as it would require or be undertaken on the basis of guiding principles within the Rules, is a regulatory design task of substantial complexity, involving issues of measurement, policy principle and possible implementation issues; and

- **Capital expenditure incentive schemes** – in circumstances in which the Commission determined to go beyond a rejection of the rule change proposal as made, and potentially explore the development of detailed rules-based incentive schemes. The network sector has developed a number of refinements to the criteria for the development of a capital expenditure scheme, which by contrast are of a more constrained scope and designed to be compatible with the timelines of the current rules change.

For these reasons the network sector suggests that a positive consideration for the AEMC in moving to a draft Rule determination should be the establishment of separate review processes to take forward the detail of the issues identified above, in recognition of the significant risks and costs to the long-term interests of consumers arising from a contracted process of assessment and design.

A further factor relevant to the timeline of the AER rule change is the need for implementation of any rule changes to be consistent with maintenance of a workable, transparent and procedurally fair regulatory framework for those network businesses which are shortly to be moving into the formal regulatory reset process. These businesses (in particular, New South Wales, Tasmanian and ACT networks) are already preparing for the regulatory proposal process with significant uncertainty over the future operation of key elements of the regulatory assessment framework affecting how capital and operating programs are to be assessed, the discretionary powers available to the AER to no longer assign significant weight to the regulatory proposal document, and other rule requirements.

These issue place further emphasis on the need to carefully scope rule changes that are feasible to develop to a final determination stage in this review, and consider the need for transitional arrangements that provide required certainty in appropriate circumstances. The circumstances of these businesses also point to the need for ongoing weight to be placed on the goal of overall regulatory stability, as a number of these businesses were subject to a comparable lack of certainty (and the need for transitional arrangements) over elements of the regulatory framework arising from delays in the finalisation of the original Chapter 6 electricity distribution rules.

3.3 Comments on assessment criteria

The network sector supports the specific focus given in the Direction Paper to the rule making test, and the continued application of its prior ‘screening’ questions that formed part of its Consultation Paper. The continued stable interpretation of the rule making test provides an important element of regulatory certainty for providers of debt and equity capital to invest in long-lived energy infrastructure.

In recognition of this the network sector encourages a strong focus by the Commission on the national electricity and gas objectives, together with the revenue and pricing principles, as the fundamental reference point for each rule change request.

While further individual specification of the manner in which proposals may meet the rule-making test, and be consistent with the revenue and pricing principles, it is the ENA’s view that a positive feature of the review of the *National Electricity Rules* was the simplification of the multiple over-layed objectives and considerations within which the previous regulatory framework (that is, the National Electricity Code) was framed.

For this reason, the ENA considers a focus on the simplified objectives, which now form part of a coherent rule making test, is potentially superior and more transparent to the iterative development of subsidiary rule change assessment frameworks.

Question 1 **Is the Commission’s assessment approach, as set out in Chapter 2 and Appendix B, appropriate? Are there other factors that should be taken into account in assessing the rule change requests?**

The ENA does not propose to comment in detail on the Commission’s rule change assessment criteria.

The relevant test for the making of Rules by the Commission is that set out in the National Electricity Law and National Gas Law – being whether the making of the Rule will contribute to the achievement of the national electricity objective or national gas objective respectively. Obviously this is the “touchstone” that the Commission must return to when assessing the AER’s and the EURCC Rule change proposals.

When considering the making of a Rule that is different to that which has been proposed the relevant test is whether the more preferable Rule will or is likely to better contribute to the achievement of the national electricity objective or national gas objective as relevant.

In response to the Commission’s rule change assessment criteria, the ENA simply notes that there is no substitute for the actual tests that the Commission is required to apply in making Rules and it is by reference to these tests that the Commission must ultimately determine whether any particular Rule should be made.

Further to the above point the ENA submits that the Commission should not make Rules in the absence of evidence that the current Rule that is sought to be amended is not working or operating as intended. The drafting of both Chapter 6 and Chapter 6A (and the National Gas Rules) was undertaken against the background of detailed consideration of the policies that should be reflected in the regulatory frameworks applying to electricity and gas networks. That is not to say that the current Rules cannot be improved through appropriate amendments where there is evidence that the Rules are not operating as they should be, but that the Commission should at each point explicitly consider whether the making of the Rule demonstrably contributes to the achievement of the national electricity objective or national gas objective as relevant.

4. Capital and operating forecasts and incentives

4.1 Capital and operating forecasting

The capital and operating forecast and incentives framework is critical to the operation of the network pricing framework. The AEMC has requested further evidence on the causes of network price increases, including evidence of any linkage between the regulatory framework and recent network prices increase. In its Directions Paper the AEMC also identified an intention to examine the policy intent of the original 'fit for purpose' model that formed part of the AEMC's Chapter 6A determination.

The ENA has now completed an extensive project of analysis surrounding cost drivers in the network sector. The result of this analysis shows that there have been diverse drivers across a range of jurisdictions, but also some common key factors that do not relate to the regulatory framework.

The network sector has also commissioned work surrounding the results of two recent reports which seek to apply benchmarking techniques to network charges, and final energy costs, to demonstrate claimed flaws in the design or application of network regulation. Both of these reports have significant empirical limitations, and are not a sound evaluative basis for critical regulatory policy design questions and issues facing the AEMC.

A primary basis for the AER's proposed rule change is its argument that the current operating and capital cost forecast is an inappropriate basis for regulatory decision-making. The Commission has observed that it is unclear whether the issues identified by the AER are evidenced by practice to date. The network sector provided substantive evidence on this issue in response to the previous *Consultation Paper* released by the Commission. In the discussion further below, it is evident that the way both Chapter 6 and 6A have been applied is consistent with the policy intent as set out in the 2006 Commission determinations.

4.2 Answers to specific questions

Question 2 **The Commission seeks further evidence on the drivers for increases in network costs, and in particular on the link between capex and opex allowances under the NER and such increases in network costs.**

The AER has suggested that recent price increases, at least in part, reflect the inability of the current regulatory framework to constrain such prices. In particular, the AER claims that its ability to regulate the prices of NSPs is hampered by:

- The requirement that it accept a forecast if it is satisfied that the forecast "reasonably reflects" efficient costs, the costs a prudent operator in the circumstances of the network service provider would require and a realistic expectation of demand and cost inputs; and
- The requirement that a NSP's submission form the AER's starting point for developing a substitute forecast should it reject that NSP's forecast.

The AEMC's review of many of the AER's regulatory determinations found no evidence that the AER has been constrained in a way that would prevent it from establishing appropriate prices. This is consistent with the analysis of our own expert advisors, as provided to the Commission in response to the Consultation Paper.[1]

[1] Joint Report *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, 8 December 2011, Attachment C

The AEMC concluded that its analysis of the data and submissions do not support the AER's claim that it has been limited in its assessment of capex and opex proposals under the NER. The ENA agrees that the material put forward so far does not provide any evidence in support of the AER's and MEU's proposition that recent NSP price increases have been caused by any deficiency in the rules.

However, the Directions Paper emphasises that the extent to which the NER may have contributed to higher than necessary network charges remains a key issue. The AEMC has called for further evidence 'on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges'.[2] In response to this, the ENA has commissioned its experts to undertake two pieces of analysis.

- The first is a comprehensive assessment of the factors causing price/revenue increases for each NSP, as specified at its most recent price/revenue determination. This analysis identifies the extent of the contribution to price/revenue increases for each NSP from increases in the WACC, capex allowances, opex allowances and other factors. It then tests whether the underlying reasons for the price increases bear any relation to the changes in the rules.

- The second piece of work commissioned by the ENA is a review of the analysis put forward in the Mountain (2011) paper entitled *Australia's Rising Electricity Prices and Declining Productivity: The Contribution of its Electricity Distributors*. In conjunction with this, the ENA also asked its consultants to consider the recently published Mountain (2012) paper entitled *Electricity Prices in Australia: An International comparison*.

The findings of these two assessments are discussed below.

Conclusions from the review of actual cost drivers

The ENA commissioned NERA Economic Consulting (NERA) to analyse the extent to which recent network price changes for both transmission and distribution businesses have been the result of changes in the Weighted Average Cost of Capital (WACC) allowed by the AER, increases in the forecast capex allowances and increases in the forecast opex allowances. NERA used the Price Tax Revenue Model (PTRM) for each business to estimate the P_0 change that would have resulted if the AER's decision at its last determination had adopted:[3]

1. the WACC allowed in the previous regulatory decision;
2. the real forecast capital expenditure allowed for in the previous regulatory period; or
3. the real forecast operating expenditure allowed for in the previous regulatory period.

For each business, NERA considered each factor in isolation, keeping the other two factors constant. NERA also identified the residual impact of other factors on the P_0 increase, outside of the above three factors. NERA's analysis covers all of the DNSPs and TNSPs in the NEM, with the exception of Powerlink (Queensland) and Aurora (Tasmania), where the AER has yet to make a Final Determination pursuant to the "new" Chapter 6 and Chapter 6A.

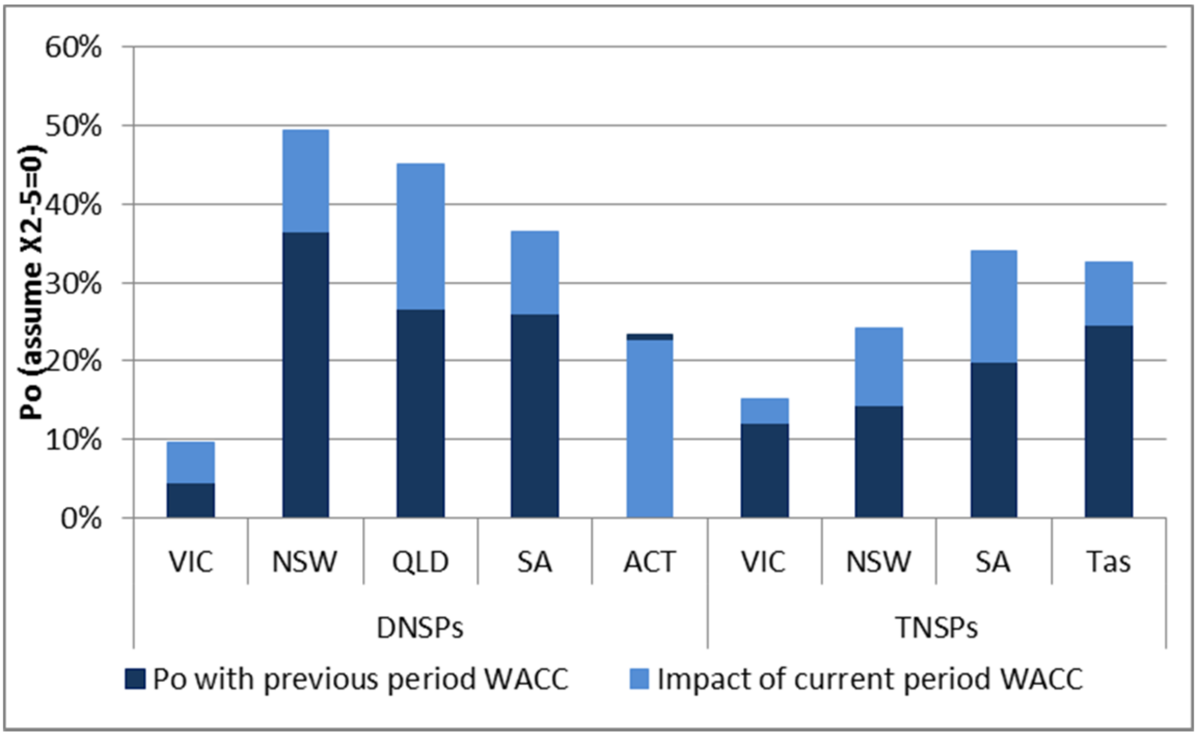
In addition to identifying the contribution of these factors to the overall P_0 increase, NERA assessed the extent to which the increase in these factors, for those businesses with the largest P_0 increases, reflects circumstances that the AER explicitly accepted as having driven the increase, as opposed to shortcomings in the regulatory framework.

[2] AEMC Directions Paper, March 2012, p.28
[3] NERA has used the PTRM models as adopted by the AER in its Final Decision, with the exception that for ElectraNet NERA has used the more recent PTRM model which incorporate the outcome of AER approvals for contingent projects. The analysis does not reflect the outcome of the Australian Competition Tribunal decision for the Victorian NSPs, this updated analysis can be provided upon request.

Impact on P_0 of the increase in WACC

Figure 1 highlights the significance of the change in the WACC in terms of the increase in P_0 in each jurisdiction.

Figure 1 - Significance of WACC in Driving P_0 Increases



Source: NERA analysis.

The increase in the allowed WACC between periods has contributed significantly to the P_0 change in almost all jurisdictions analysed. Only for the ACT was the change in the WACC found to have a minor impact on overall change in P_0 (and, indeed, to act to reduce the overall P_0).

The increase in WACC is also significant in terms of the materiality of its impact on the overall P_0. In Queensland the change in WACC results in an 18% increase in P_0 for DNSPs (on a weighted average basis), ie, an increase from 27% to 45%. Similarly, in NSW the change in WACC results in an 12.8% increase in P_0 for DNSPs (on a weighted average basis), ie, an increase from 36% to 49%, whilst in South Australia the change in WACC accounts for a 14.1% increase in P_0 for ElectraNet, ie, an increase from 26% to 36%.

NERA found that the increase in WACC between regulatory periods is predominantly due to a higher debt risk premium. The increase in the debt risk premium is in turn substantially due to a change in market conditions (predominantly the impact of the global financial crisis), leading to increases in the observed debt risk premium, even though the benchmark remained unchanged.

Specifically, for DNSPs, the benchmark now adopted by AER (BBB+, 10 year) is either the same as or a slightly higher grade of debt than that adopted by the previous jurisdictional regulators at the time of the earlier regulatory decisions. This implies that, absent any change in market conditions, the debt risk premium would have been the same or lower for the DNSPs. For the TNSPs the AER benchmark (again, BBB+, 10 year) has been modestly reduced from that applied in the previous regulatory period (i.e., A, 10 year). However the change in the benchmark was determined by the AER as appropriate in the 2009 SORI[4]. In neither case does the change in the debt risk premium reflect a shortcoming with the Rules.

Impact on P_0 of the increase in capex allowances

Figure 2 highlights the significance of the change in the increase in forecast capex allowances in terms of the increase in P_0 in each jurisdiction

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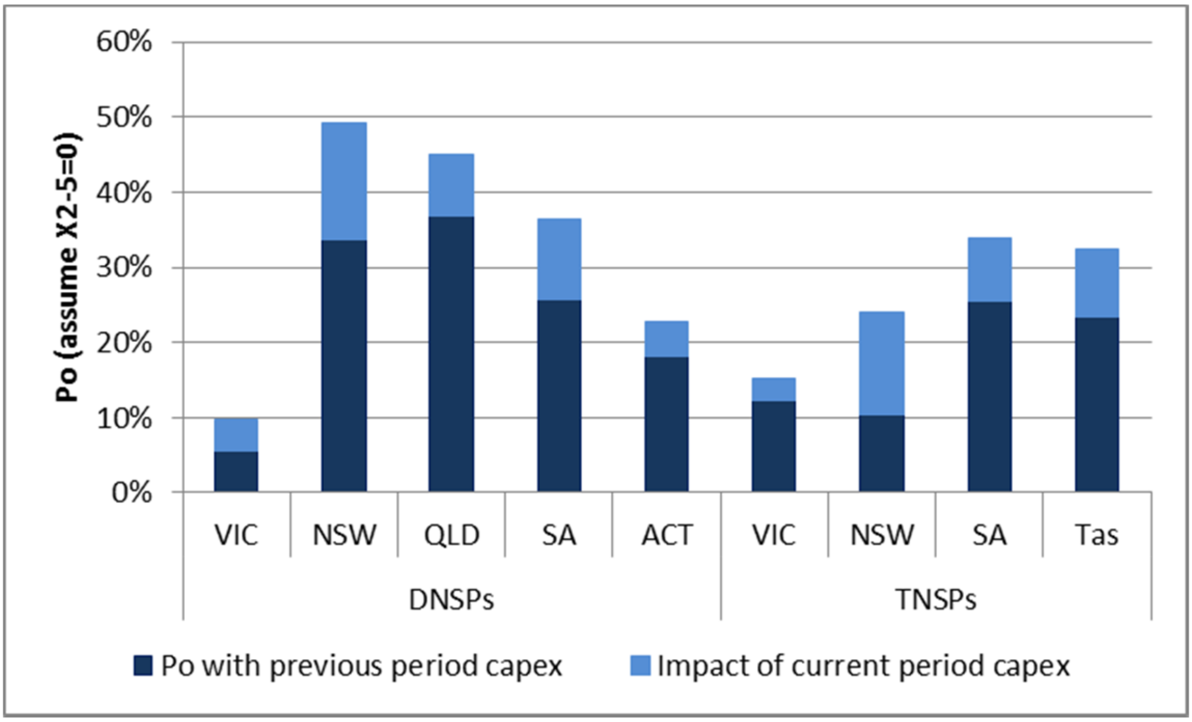
Figure 2 - Significance of Capex Forecast in Driving P_0 Increases



Source: NERA analysis.

The increase in the capex allowance between periods has contributed significantly to the observed P_0 rise in all jurisdictions analysed. Specifically, the increase in allowed capex between periods is found to represent at least 18% of the overall change in P_0 for all jurisdictions.

The impact of the increase in allowed capex is the most material in NSW and South Australia. The increase in forecast capex allowances in NSW results in a 16% and 14% increase in P_0 for DNSPs and TNSPs respectively (on a weighted average basis), ie, an increase from 34% to 49% for DNSPs and an increase from 10% to 24% for TNSPs. In South Australia, the increase in capex allowance implies an increase of 10.6% in the P_0 for the DNSP (ETSA Utilities), ie, an increase from 26% to 36%.

In order to identify the key drivers of the increase in capex forecasts, NSPs were asked to complete a template which included a breakdown of the capex allowance in the current and previous regulatory periods into key component categories. The key drivers of the increase in the capex allowance differ across NSPs, but augmentation to meet peak demand growth, asset renewal/replacement and environmental, safety and statutory obligations and new customer connections are categories of

[4] AER (2009), *Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution).*

expenditure that have contributed substantively to the overall increase in capex allowance for a large number of DNSPs and TNSPs.

In the case of augmentation to meet peak demand growth, we note that it is increases in peak demand at a particular feeder level which are the key driver of network capex, rather than the system-wide increase in peak demand. This is particularly the case for networks which have a wide geographic spread, and where different parts of the network are facing different peak demand growth conditions (eg, due to the different composition of load in each area).

Capex to meet enhanced distribution reliability standards in NSW was identified as a key driver for the increase in Essential Energy's capex forecast. The increase in distribution network reliability standards in both NSW and Queensland has also contributed to the increase in capex allowances to meet higher peak demand for some DNSPs. The increase in standards also contributed to an overspend in capex in the previous regulatory period for the Queensland DNSPs, which is in turn an 'other factor' driving P_0 increases (see discussion below).

The increase in capex allowance has been a key driver for Ausgrid (both transmission and distribution), Essential Energy and ETSA Utilities. NERA's analysis concluded that:

- For **Ausgrid** (NSW) (both transmission and distribution): the key drivers of the increase in capex allowance were (i) asset renewal/replacement; and (ii) augmentation to meet peak demand growth – with these two categories accounting for approximately 80% of the overall increase in the approved total capex forecast;

- For **Essential Energy** (NSW): the key drivers of the increase in capex allowance were (i) augmentation to meet peak demand growth; (ii) quality, reliability and security of supply enhancement; and (iii) asset renewal/replacement – with these three categories accounting for approximately 87% of the overall increase in the approved total capex forecast;

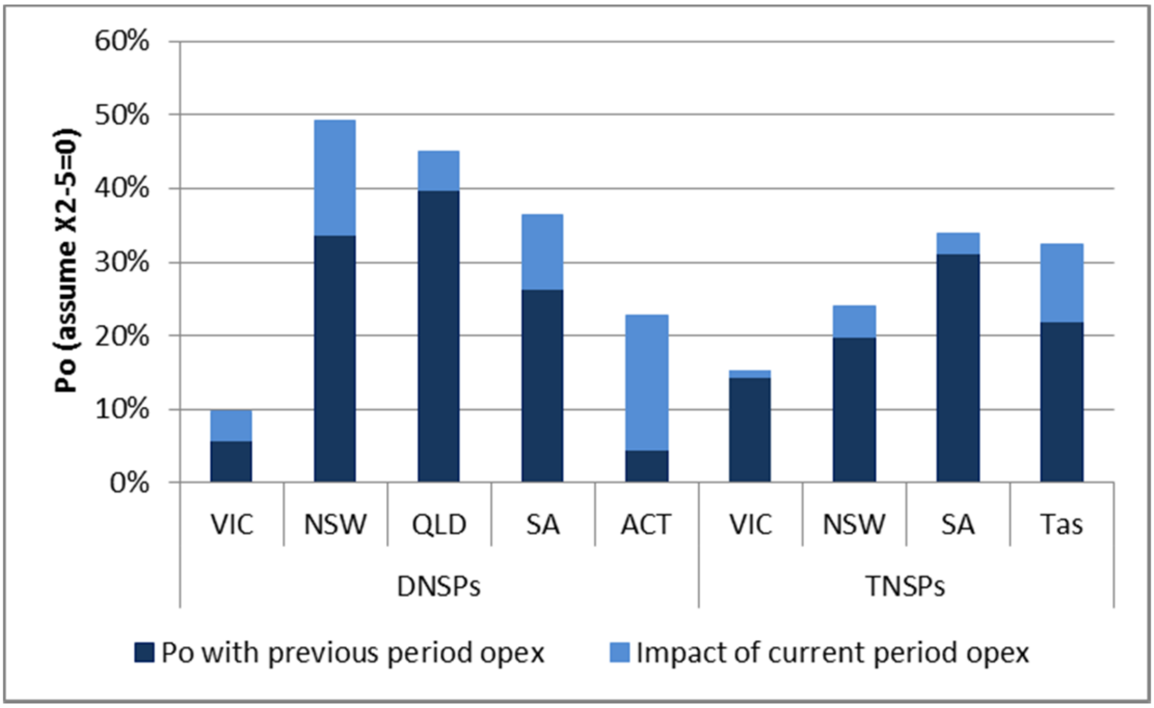
- For **ETSA Utilities** (SA): the key drivers of the increase in capex allowance were (i) augmentation to meet peak demand growth; and (ii) non-network capex - with these three categories accounting for approximately 69% of the overall increase in the approved total capex forecast

For all three NSPs, the key drivers of the increase in capex forecast were examined by independent engineering consultants appointed by the AER. Both the consultants and the AER concluded that the capex allowance for these categories reflected the prudent and efficient level of expenditure. The evidence therefore indicates that, for these businesses, the key drivers of the increase in capital expenditure allowances reflect circumstances (eg, increases in peak demand; asset condition) which have been recognized as legitimate drivers of expenditure by the AER and its engineering advisors, rather than reflecting a failing in the regulatory regime.

Impact on P_0 of the increase in opex allowances

Figure 3 highlights the significance of the change in the increase in forecast opex allowances in terms of the increase in P_0 in each jurisdiction.

Figure 3 - Significance of Opex Forecast in Driving P_0 Increases



Source: NERA analysis.

The increase in the allowed opex between periods has contributed significantly to the observed P_0 rise in almost all jurisdictions analysed. Specifically, only for ElectraNet (South Australia) and SP AusNet transmission (in Victoria) is the increase in opex allowance found to represent less than 10% of the overall change in P_0.

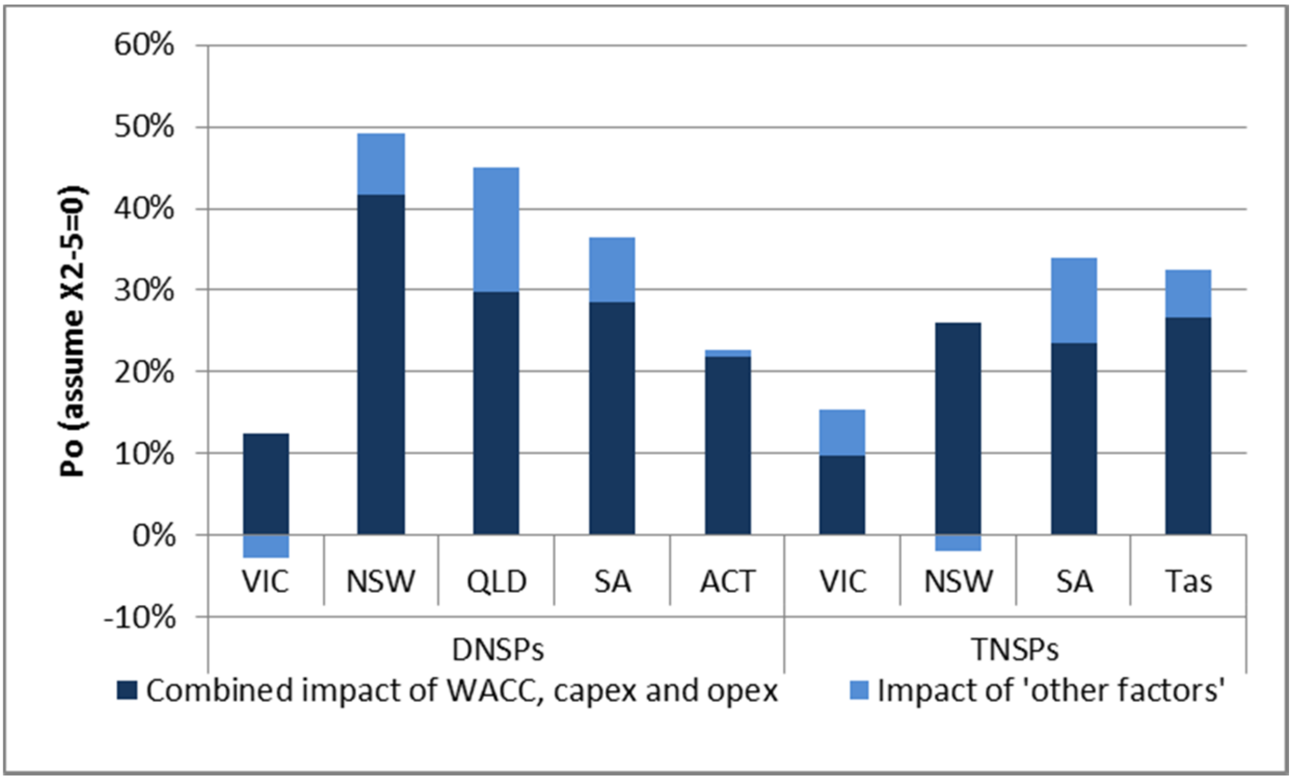
The impact of the increase in allowed opex is the most material for the DNSPs in NSW, South Australia and the ACT as well as for the TNSPs in Tasmania and Victoria. The increase in forecast opex allowance in the ACT results in an 18% increase in P_0 for ActewAGL, ie, an increase from 4% to 23%. For the NSW DNSPs the increase in P_0 due to the higher opex allowance is 15.6% (on a weighted average basis), ie, an increase from 34% to 49%, whilst for ETSA Utilities (South Australia) the increase is 10%, ie, an increase from 26% to 36%. In Tasmania, Transend's increase in P_0 due to the increase in opex allowance alone would have been 10.6%, ie, an increase from 22% to 33%.

The increase in opex allowances reflects circumstances which have been recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime. Specifically, NERA found that the drivers behind the increase in opex reflects a combination of factors, such as real wages growth, increased legislative obligations (including feed-in tariffs), and an expansion of the capital base. For the businesses NERA reviewed, in all cases the AER had the NSP's forecasts reviewed by independent consultants. In the case of Transend (Tasmania), ActewAGL (ACT), ETSA Utilities (SA) and Essential Energy (NSW), the AER applied reductions to the allowed opex forecast over and above those that had been recommended by the external consultants. It is noted here that in many cases decisions to adjust expenditure are based on external independently obtained expertise given by parties less constrained than the AER in assessing levels of efficient expenditure.

Other factors

Figure 4 highlights the significance of other factors (besides changes in allowed WACC, capex and opex) in terms of the increase in P_0 in each jurisdiction.

Figure 4 - Significance of Other factors Forecast in Driving P_0 Increases



Source: NERA analysis.

Figure 4 shows that the contribution of other factors on the change in P_0 is less than the combined contribution of the changes in WACC, capex and opex. However the impact of other factors does remain a substantive component of the overall change in the P_0 for all jurisdictions, with the exception of the ACT.

The impact of other factors is the most material for the Queensland DNSPs and ElectraNet (SA). The impact of other factors in Queensland has resulted in a 15% increase in the P_0 for DNSPs (on a weighted average basis), ie, an increase from 30% to 45%. For ElectraNet (SA), the impact of other factors increased the P_0 by 10.3%, ie, an increase from 24% to 34%.

The 'other factors' affecting the P_0 outcomes encompass a variety of things, including the realignment of tariff revenue to costs in the final year of the previous regulatory period arising from:

- forecast smoothed revenue for the previous period differing from forecast building block costs;
- forecast operating costs for the previous period differing from actual operating costs;
- forecast capital expenditure for the previous period differing from actual capex; and

- for those NSPs subject to price cap regulation, differences between forecast and actual demand in the final year of the previous regulatory period.

P_0 outcomes will also be affected by revenues associated with the operation of the Efficiency Benefit Sharing Schemes (EBSS) and other incentive schemes.

Importantly, these factors reflect the legitimate outworkings of the regulatory modelling, rather than any shortcomings in particular regulatory rules.

Energex (Queensland) advised NERA that the following 'other' factors help explain its real price increase in the current regulatory period (noting that the first two are likely to account for the majority of the gap):

- In the previous regulatory control period (ie, 2004/5-2009/10), Energex spent above its capex allowance, primarily to address compliance obligations arising from the Electricity Distribution Service Delivery review and to meet demand growth on its network. This contributed to a higher starting Regulatory Asset Base (RAB) for the current regulatory period;

- The tax allowance component under the Queensland Competition Authority's building block approach was based on actual tax paid, which is substantially lower than the assumed benchmark tax costs adopted by the AER; and

- In the previous regulatory control period (2005-06 to 2009-10), Energex's revenue was reduced to account for over-recoveries, adjustments to asset lives and opex carry forward from the 2001/02 to 2004/05 regulatory control period. These adjustments, totalling $234 million, understated the efficient costs in the previous regulatory control period. In addition, the 2009-10 revenue included a downward adjustment of approximately $20.4 million for over recovery in 2007-08 which further understated the starting revenue resulting in a higher Po

Ergon Energy (Queensland) advised NERA that the following 'other' factors help explain its real price increase between periods:[5]

- In the 2005-10 regulatory control period, Ergon Energy spent above its capex allowance, primarily to address customer and demand growth on its network. This contributed to a higher starting RAB for the current regulatory period;

- The tax allowance component under the Queensland Competition Authority's building block approach was based on actual tax paid, which is substantially lower than the assumed benchmark tax costs adopted by the AER;

- There was a carry forward amount of $10.7 million ($2009-10) for accelerated depreciation due to Cyclone Larry from the previous period which further increased the allowed revenue in the first year of the current period; and

- The starting point of the 2009-10 revenue included a net over-recovery adjustment of approximately $9.3 million for revenue over recovery, cost pass through for Cyclone Larry and exclusion of excluded distribution services revenue, which would understate the starting revenue and overstate the overall P_0.

ElectraNet (SA) advised NERA that the following 'other' factors help explain its P_0 increase between this period and the last:[6]

[5] Similar to Energex, Ergon Energy noted that the first two are likely to account for the majority of the gap.
[6] Note all figures are provided in $2007/08.

- $21m extra for capitalised equity raising costs - equity raising costs in the previous regulatory period were provided for by the ACCC as an allowance in perpetuity and the AER converted this into an amount capitalised in the RAB as part of the most recent decision;

- $29m for easement compensation costs;

- A further $46.6m for easement transaction or acquisition costs, granted as a result of merits review; and

- $17m for readmission of optimised assets.

Conclusions from the critique of Mountain (2011)

Bruce Mountain has prepared two papers for the Energy Users Association Australia (EUAA):

- Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors (Mountain (2011)) published in May 2011;[7] and

- *Electricity Prices in Australia: an International Comparison* (Mountain (2012)) published in March 2012.[8]

Following a review of the expenditure allowances of distribution network service providers (DNSPs), Mountain (2011) concludes that regulatory failure and government ownership are the major causes of recent price increases, rather than the oft cited need for investment to replace aging assets and meet the requirements of rising peak demand. On this basis, Mountain makes a number of recommendations that, the paper argues, would raise productivity in this sector.

Our assessment of the analysis undertaken in Mountain strongly suggests that it provides an insufficient basis for such conclusions. Failure to consider the many legitimate reasons for variances in costs per connection and a reliance on inappropriate comparisons has resulted in Mountain drawing unsubstantiated conclusions about the relative efficiency of DNSPs. Mountain's focus on ownership as the key distinction between DNSPs omits consideration of state-specific cost drivers.

Mountain begins by comparing revenue, capex and the value of the Regulatory Asset Base (RAB) per connection within each state, on a weighted average basis. The paper notes that growth in each of these ratios has been substantially higher for DNSPs in Queensland and New South Wales as opposed to South Australia and Victoria. On this basis, Mountain concludes that the financial performance of Government-owned DNSPs, being those in Queensland and New South Wales, is relatively poor compared to that of the privately-owned DNSPs, being those in South Australia and Victoria.

A comparison of these ratios is ill-suited to making conclusions regarding the relative efficiency of DNSPs. There are numerous reasons, besides relative efficiency, why DNSPs would have different levels of opex, capex and RAB per connection. These will include service quality standards, past expenditure decisions and the nature of the network, such as the mix between industrial and residential connections, network length, customer density, peak and average demand levels, the split between transmission and distribution networks, etc.

Furthermore, the use of averages for each state masks variations in costs between firms within a state. Such a loss of information makes it difficult to draw conclusions about the true causes of cost differences.

7 Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*, May 2011.
8 Mountain, B.R., *Electricity Prices in Australia: an International Comparison*, CME, March 2012.

Mountain discredits the suggestion that cost differences may be due to differences in service quality by presenting the average from 2001 to 2009 of the *System Average Interruption Frequency* and the *System Average Interruption Duration* Indices. These averages show that service performance in New South Wales and Queensland has arguably been slightly poorer over this period than in Victoria and South Australia. The relevance of this information is highly questionable, given that Mountain is largely concerned with price increases that have occurred from around 2009 onwards, that is, after the period for which the quality data is presented. Its relevance is even further eroded by Mountain's use of the nine year averages, rather than presenting the time series on an annual basis.

Mountain (2011) develops a composite scale variable (CSV) to assess the relative efficiency of the DNSPs. In essence, this analysis assumes that customer numbers and network length are the only drivers of DNSP costs. In our opinion, that is not a reasonable assumption, since it overlooks the many other potential sources of cost differentials. This approach, therefore, does not provide a sound basis upon which to draw any conclusions regarding the relative efficiency of businesses.

Mountain (2011) also provides a comparison of the costs of NEM and UK distribution companies. However, making such comparisons is not straightforward and there are a number of potential shortcomings with the analysis presented by Mountain (2011) that reduces its applicability. For example:

- The use of different exchange rates can greatly affect the results and it is arguably more appropriate to use a Purchasing Power Parity (PPP) index rather than a market exchange rate for making comparisons. The use of a PPP index significantly reduces the gap between NEM and UK costs;

- Government policies and system standards can affect prices; and

- Regulatory and accounting differences between jurisdictions can mean that costs are not directly comparable.

Furthermore, even if one can conclude that costs are higher in the NEM than in the UK, there are many legitimate reasons why this may be the case. For instance:

- There may be many differences in the characteristics of the networks being considered, such as the line length and the level and change in peak demand;

- There may be distortions in the current prices due to past regulatory decisions;

- There may be legitimate differences in the cost of inputs, particularly, the cost of capital is likely to be higher for Australian DNSPs.

It would be inappropriate to conclude that NEM distributors are less efficient than their counterparts in the UK on the basis of the comparisons provided by Mountain.

Mountain reviews a number of potential cost drivers that may have been responsible for recent price increases in Australia. In our view, a number of conspicuous deficiencies in Mountain's analysis mean that one cannot reasonably conclude that Government ownership and the regulatory framework are the key drivers of price increases.

First, Mountain dismisses the claim that investment has been driven by the need to meet rising peak demand by considering the growth in *historic aggregate* and *average* demand. Mountain finds that growth related expenditure has been four times higher for Government owned NSPs even though average demand has grown more strongly in Victoria than in Queensland or New South Wales. However, networks must be configured to meet peak demand, not average demand. Furthermore, the demand growth considered by Mountain is *historic* not forward looking. NSPs must invest to meet anticipated demand growth, not past demand growth. The AEMC has previously published[9] forecast growth in maximum demand in the NEM that suggests NSW and Queensland DNSPs are likely to experience stronger future growth than those in South Australia and Victoria.

Mountain rules out claims that investment has been driven by the need to replace aging assets on the basis of the *average effective remaining life* of assets for the various DNSPs. However, the average effective remaining life is only of limited applicability for determining the value of assets that need replacing in any year, it is the age profile of assets that is more relevant.

Mountain also dismisses claims that there is an element of "catch-up" in investment due to past levels of under-investment. Mountain notes that many commentators have expressed a view that there has been under-investment in the past but dismisses these claims on the basis of a study carried out in the 1990s, which concluded that *between 1982 and 1994* NSW distributors were inefficient and capital productivity was poor. Inefficiency and low capital productivity tells us very little about past underinvestment levels, especially when such a study refers to information that is up to 30 years old.

The ENA is of the view that the analysis provided in the NERA report *Analysis of Key Drivers of Network Prices Changes*, which was discussed above, provides a significantly better basis for determining the actual cost drivers that have led to the recent price increases.

Mountain's second paper for the EUAA, *Electricity Prices in Australia: An International Comparison* considers household retail prices and concludes that Australian prices are high and rising relative to those in other countries. This paper was not submitted to the AEMC as part of the review of the NER and is of limited relevance as it considers retail prices, and only for household customers, rather than the costs of DNSPs. However, given the timing of its release it may receive some attention in the course of this review and is therefore worthy of comment.

It is interesting to note that, although Mountain provides price comparisons on the basis of both market exchange rate and purchasing power parity (PPP) adjustments, the focus of the paper is on the former. However, the PPP-based comparisons are arguably more informative and significantly lower the Australian retail prices relative to those in other countries. On this basis, Mountain shows that Australian household retail prices are actually lower than those in Japan and the EU.

It is also important to bear in mind that the overseas data is older, further reducing the relevance of the comparison. Specifically, the Canadian and Japanese prices are for the 2010 calendar year.

In fact, the conclusions Mountain draws are inconsistent with those reached by a number of other commentators. For example, a 2012 report by the Bureau of Resources and Energy Economics concluded that Australian Household electricity prices were the 24th cheapest out of 32 OECD countries.[10]

Finally, it must be borne in mind that many other factors may result in differences in retail prices including government policies, how electricity is generated and geographical and meteorological factors. Even if Mountain's comparisons did credibly establish that retail prices in Australia were higher, which it does not, there are many potential, legitimate, explanations for why this may be the case.

Overview of operating expenditure incentives

In the course of the consultation phase to date, the AEMC has given very limited or no acknowledgement of the opex incentive arrangements that are intrinsic to the existing framework and the extent to which these arrangements can provide comfort that NSP's opex is reasonable and efficient.

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[9] AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.11
[10] Bureau of Resources and Energy Economics, *Energy in Australia in 2012,* February 2012, p.41.

It is the NSPs who ultimately determine whether or not efficiency gains are made. Generally speaking, making efficiency gains requires effort on the part of the NSP. To the extent the rewards from such efforts are taken from the NSP, these companies will have a lower incentive to engage in efficiency-enhancing activities.

The fundamental objective of an efficiency sharing scheme is to enhance a NSP's incentive to pursue efficiency gains, particularly given the periodic nature of five year price reviews and the associated discontinuities in incentives around those reviews. The benefit of enhanced, or smoothed, incentives for efficiency gains is that the cost of providing services becomes less than would otherwise be the case, which ultimately translates into lower consumer prices thereby contributing to the long term interests of consumers.

Under the scheme, a continuous incentive to achieve efficiencies is provided by allowing the NSP to retain, for a fixed period the difference (negative or positive) between its actual and forecast operating expenditure. Any such difference arising in any year of the regulatory period is retained by the TNSP and carried forward for five years following the year in which the efficiency gain or loss is incurred. In this way, the scheme encourages firms to remain efficient throughout the period rather than to concentrate efficiency gains during the early part of the period.

At the end of the five year period, the total value of the gain or loss is removed from the NSPs expenditure forecast and thereby "shared" with network users in the form of lower prices.

Without such a scheme, NSPs would face a diminishing incentive during a regulatory period to initiate efficiencies in delivering opex. For instance, if the efficiency occurred in year 1 and the gains occurred without lag, the service provider would retain the benefit of the efficiency saving in each year of the regulatory control period. However, where an efficiency saving occurred in the latter years of the regulatory control period the service provider would only enjoy the benefit for the remaining years of the regulatory control period.

In regard to the EBSS for TNSPs the AER stated:[11]

> *The scheme exists to give regulated monopoly businesses an incentive to respond to opportunities to achieve efficiency gains, as would otherwise occur in a competitive market. Under the ex ante regulatory framework a service provider retains the benefit (higher profits) of achieving opex outturns below the level forecast in its revenue determination. If the opex outturn exceeds the forecast, the service provider suffers an opportunity cost (profits below those implied by the revenue determination).*

The Joint Expert Report on Capital and Operating Expenditure has commented specifically on the incentives for efficient operating expenditure in the current NEM framework. In doing so, the report comments on the ways in which an EBSS for operating expenditure seeks to achieve efficiency gains:[12]

> *"The design of the AER's EBSS improves NSPs' incentives to seek efficiency gains in the following ways:*
>
> *1. It balances the interests of the NSPs with those of users in an attempt to mimic competitive market outcomes. The AER has stated that the five year carry-over will approximate to a sharing ratio between NSPs and network users of 30:70 (30% to NSPs and 70% to users), based on the net present value of the gains/losses over time. In assessing whether this would provide a strong enough incentive to NSPs the AER noted that it would be rare for a firm operating in a competitive market to retain the benefits of efficiency gains for a period of more than five years.*

[11] AER (2007) *Final Decision: Electricity Transmission Network Service Providers Efficiency Benefit Sharing Scheme,* p.4
[12] Joint Expert Report, *Capital and Operating Expenditure – Response to the AEMC Directions Paper,* 16 April 2012, p.25

2. The scheme provides a continuous incentive to achieve efficiencies by allowing the NSP to retain, for a fixed period, the difference (negative or positive) between its actual and forecast operating expenditure. Any such difference arising in any year of the regulatory period is retained by the NSP and carried forward for five years following the year in which the efficiency gain or loss is incurred. In this way, the scheme encourages firms to remain efficient throughout the regulatory period.

3. The AER has committed to carrying forward the entire amount of any efficiency gain (or loss) for the specified period rather than adjusting the amount on an ad hoc basis. At the time of making its Final Decision, the AER considered whether it should retain the option of adjusting any large positive carryovers to provide a greater benefit to users. The AER determined that applying all positive carryovers minimises regulatory uncertainty for NSPs and ensures consistent and continuous incentives."

Further to this, the AER also implements an exclusion policy for the EBSS for operating expenditure. The exclusion policy seeks to remove the potential for NSPs to make changes to their capitalisation policy in order to distort otherwise efficient outcomes. This is achieved by requiring an NSP to provide a detailed description of any changes in capitalisation policies that have arisen during the regulatory period or that are proposed to apply in the next regulatory period. As a result of this exclusions policy, it is clear that reported expenditure information is calculated on the same basis as the expenditure forecasts against which it is compared.

The incentives provided for efficient opex also mean that the AER can place considerable reliance upon outturn expenditure when setting future expenditure requirements. That is, the AER can start with actual expenditure in the latest observable year and carry this amount forward by a trend, subject to any step changes in costs. Thus, the task of assessing forecast operating expenditure is simplified due to the presence of an EBSS on this form of expenditure.

Question 3

Would it be appropriate for the wording of the NER to be clarified to better reflect the policy intent?

The AER has suggested that recent price increases, at least in part, reflect the inability of the current regulatory framework to constrain such prices. In particular, the AER claims that its ability to regulate NSPs prices is hampered by:

- The requirement that it accept a forecast if it is satisfied that the forecast "reasonably reflects" efficient costs, the costs a prudent operator in the circumstances of the TNSP would require and a realistic expectation of demand and cost inputs; and

- The requirement that a NSP's submission form the AER's starting point for developing a substitute forecast should it reject that NSP's forecast.

In the context of asking Question 3, the AEMC has noted that, in its view, the policy intent of Chapter 6A appears to remain appropriate and applicable.[13] The essence of this question is therefore whether the AER has applied the NER in a way that is consistent with this policy intent. It is only if this is not seen to be the case that it may be appropriate to clarify the wording of the NER.

[13] AEMC *Directions Paper* (2012), p.28

Recall that the policy intent was *"concerned with striking an appropriate balance between competing policy objectives and stakeholder interests that arise in the context of regulating natural monopoly infrastructure".*[14]

> *"On the one hand, economic regulation is adopted to address the costs and inefficiencies that can result from the capacity of TNSPs to exercise market power, while at the same time providing incentives for them to invest in and operate their networks efficiently. On the other hand, economic regulation is an imperfect substitute for effective competition and the potential for regulatory error can also impose costs and inefficiencies, including in relation to the incentive and financial capacity to undertake long-term investments in transmission infrastructure."*[15]

A key driver for the current framework was to provide NSPs with improved certainty, predictability and stability of regulator outcomes. It was considered critical that fundamental weight was provided to the network businesses' regulatory proposal as a starting point of decision-making because the inefficiencies associated with poor or erroneous regulatory decisions were, appropriately, seen to be significant.

It is the ENA's view that there is nothing in the AER's behaviour to date that can be seen to be inconsistent with the policy intent as set out by the AEMC. It is therefore the ENA's opinion that there is no reason to alter the wording of the NER. This is discussed further below.

Requirement to accept reasonable forecasts

During the consultation phase of implementing Chapter 6A, several commentators raised concerns about the requirement on the AER to accept forecasts that "reasonably reflect" the criteria. To address these concerns, the Commission deliberately left the wording in place but revised the decision criteria to be applied in determining expenditure forecasts so as to better reflect the policy balance it was seeking.

This included improving the specification of the objectives of the expenditure forecasts to be incorporated into the building block methodology and the procedural requirements for expenditure forecast proposals. The Commission also clarified the decision-making rule to provide that the AER must accept a forecast if it is satisfied that the forecast reasonably reflects efficient costs, the costs a prudent operator in the circumstances of the TNSP would require and a realistic expectation of demand and cost inputs.
The Direction Paper points out the position of the AER:[16]

> *The AER notes that the expression "reasonably reflects" in the capex and opex criteria means that there is a range of forecasts that may meet the criteria. If a forecast falls within this range, the AER must accept it, even if there is a lower possible forecast that would satisfy the criteria. In these circumstances, the AER states, a NSP will always forecast at the top of the range, leading to inflated forecasts.*

While it is possible to imagine a NSP could provide a forecast that the AER must accept as reasonable even though it may not be its preferred forecast, this has not been the experience to date. Rather, in all of its determinations, including the four TNSP determinations, the AER has rejected the total expenditure forecasts put forward by the NSP, as being above the total expenditure that reasonably reflects the expenditure criteria.[17] Therefore, experience from the AER's determinations does not support the view that the AER has been constrained under the Rules to accept a NSP's proposed total forecast when the AER considers that forecast to be inflated. The risk highlighted by the AER has not been realised in practice and to the extent the AER considers there may have been any bias in the TNSPs forecasts it has been able to remove such bias.

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[14] AEMC *Rule Determination* (2006) p.48
[15] AEMC *Rule Determination* (2006) p.48
[16] AEMC *Directions Paper* (2012), p.17
[17] A detailed review of the AER's past decisions was undertaken in PWC, Gilbert + Tobin and NERA, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure* (2011), which was submitted to the AEMC as part of the earlier consultation phase.

The AER has also expressed the concern that the current wording of the NER requires it to forecast a range of possible values that may meet the criteria. The AEMC has stated that it was not the Commission's intent that the AER be constrained to choose the highest possible level in a range.[18]

> *At the time of making Chapter 6A, the AEMC did not think that expenditure forecasts could be specified with precision; meaning that there is no best or correct figure. At the same time though, the AEMC did not intend that the NER contemplate a range of permissible outcomes such that there could be a bias towards a higher amount.*

Moreover, in practice, the AER has not formed estimates of a range of acceptable values.

It is important to bear in mind that there is no restriction under Chapter 6A for the AER to limit any adjustment of a NSPs forecasts only to the extent necessary to bring the forecast in line with a reasonable level. Therefore, once the AER has decided to reject a proposal under Chapter 6A it is at liberty to replace it with a new forecast it believes to be the most appropriate, thereby eliminating any upward bias that may otherwise have occurred.

As a result, the theoretical potential for an upward bias in expenditure forecasts that has been raised has not been demonstrated by actual determination outcomes over the last five years. Rather, the AER has determined in all cases that it is not satisfied that the NSP's forecast reasonably reflects the expenditure criteria and has substituted its own forecast of total expenditure in its determination.

We therefore conclude that AER's application of Chapter 6A cannot be said to have been inconsistent with the Commission's policy intentions. The actual experience to date does not, therefore, indicate any deficiency in the current rules in the manner in which the AER contends and there is no support for granting the AER a greater degree of discretion on the basis that the existing rules fail to comply with the policy intent.

Requirement to consider the NSP's forecasts

The objective of requiring the AER to have regard to the information provided by the TNSPs was seen as important in limiting the AER's discretion to substitute its own forecasts for those contained in the revenue proposal of the relevant NSP. The Commission considered it important that the AER be required to provide reasons for any substitution in terms of the decision criteria and factors for both a rejection of the forecasts and their replacement with forecasts that it considers do meet the requirements of the rule.[19] The earlier report by our consultants[20] noted that although the AER undertook line-by-line approaches to assessment and substitution, it was also clear in its determinations that its substitute value reflected the total expenditure forecast which it is satisfied reasonably reflected the expenditure criteria.

The AER is of the view that the NER restricts its ability to apply other techniques. However, it is not evident that this is the case under Chapter 6A. It is important to note that the concerns expressed by the AER that any substitute forecast must necessarily be undertaken on the same basis as the NSPs forecast only apply to Chapter 6 and are not relevant to Chapter 6A where there is no such constraint.

Explicit in 6A.13.2(b), the AER is not restricted to using the same methodology as the TNSPs in assessing and substituting expenditure. Should the AER decide it is not satisfied with a TNSPs forecast, it is at liberty to substitute a value for total expenditure based on an approach other than a line-by-line substitution, assuming that the AER could justify such an alternative approach.

[18] AEMC *Directions Paper* (2012), p.16
[19] AEMC *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18,* 16 November 2006, p.53
[20] NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011, p.22

The ENA does not, therefore, consider the current constraints requiring the AER to consider the submissions of the NSPs' to be inconsistent with the policy intent of Chapter 6A.
In fact, it is highly likely that without the constraints requiring the AER to place considerable weight on the NSPs submissions, the regulator may have behaved in a way contrary to the policy intent. This would increase the risk of regulatory error and introduce considerable uncertainty into the regulatory framework.

The AER must have due regard to the information submitted by an NSP but this does not preclude:

- Appropriate judgements as to the materiality of particular information; or
- The use of sampling techniques with extrapolation of the findings to other line items.

In practice, the AER has not considered every line of each NSP's forecast but rather has relied on extrapolation techniques. Evidence of this was provided in the joint expert report submitted by the ENA on 8 December.

Conclusion

The way in which Chapter 6A has been applied cannot be seen to be inconsistent with the policy intent as set out in the AEMC's Rule Determination.

- The AER has given considerable attention to NSPs' submissions, using them as a starting point, as intended by the Commission in order to mitigate regulatory risk.
- The requirement to accept forecasts that "reasonably reflect" the criteria has not resulted in the AER either:
  - Needing to establish a range of acceptable levels for opex and capex; or
  - Being forced to accept forecasts it considers inappropriately high, as in each case the AER has rejected the TNSPs forecasts, replacing them with its own forecasts; and
- Although, it is possible to imagine a NSP could provide a forecast that the AER would need to accept as reasonable even though it may not be its preferred forecast, this has not happened to date, and the risks around this are therefore untested.

Experience to date does not, therefore, indicate any deficiency in the current rules as they relate to the Commission's policy intent. There is no evidence to support an argument for granting the AER a greater degree of discretion on the grounds that the existing rules are failing to comply with the policy intent.

Question 4 - What circumstances of the NSP should the AER be required to take into account when benchmarking?

It is a fundamental requirement of benchmarking exercises to take account of differences in the business environment facing an NSP.

This includes considering such factors as:

- reliability and service standards and jurisdictional obligations;
- the density of the customer base;
- customers' load profile;

- network characteristics (e.g. underground versus overheads, age of the network, etc);
- the mix of industrial (high voltage) and domestic (low voltage) consumers;
- the nature of the terrain and climate, and so on.

It is clearly not appropriate for a benchmarking exercise to make adjustments for circumstances such as the quality of management or the nature of ownership. However, there is no evidence of any party suggesting or attempting to make such adjustments in the context of regulatory decision-making.

Question 5 – Would it be appropriate for the capex objectives to be clarified to better reflect jurisdictional reliability standards?

It would be appropriate to amend the capital expenditure objectives to clarify that capital expenditure forecasts should seek to target mandated service and reliability standards. Where these standards have been amended, the current reference to the goal of "maintaining" existing levels of performance has the potential to cause a lack of clarity for both the service provider and AER alike.

Question 6: What factors or features of the approaches of other regulators should be taken into account when reviewing other regimes to confirm the best practice approach to economic regulation?

The Commission has expressed the view that the current regulatory policy intent remains appropriate and relevant but has asked whether there is anything that can be learned from other regulatory regimes that would suggest "best practice" has developed from the time this policy intent was put in place. Specifically, the Commission has highlighted the fact that New Zealand and the United Kingdom have undertaken significant reviews of regulatory practices since 2007.

Given the issues the Commission is interested in assessing, the features of the approaches of other regulators that it may want to consider in its review of other regimes include:

(1) Whether other regulators begin their determinations with a review of a submission by a regulated entity;

(2) The recourse other regulators have to other information sources and the relative weight they place on them, for example:

   a. Benchmarking

   b. Other submissions, for example, from network users

(3) The decision criteria applied by other regulators as to whether a regulated entity's submissions are rejected or accepted.

The ENA sought the view of its expert consultants regarding the extent to which the approach of other regulators is consistent with the policy intent of Chapter 6A.

In relation to New Zealand, they have noted that the regulatory framework has recently been changed with the implementation of the Commerce Amendment Act 2008. This was intended to improve the regulatory framework in a number of ways, one of the key objectives being to improve the level of regulatory certainty by limiting the extent of discretion available to the Commission. A further objective was to improve the accountability of the Commission as most decisions were previously subject only to judicial review and not to an appeal against the substance of those decisions.

On its face, the fact that the Commission sets its own regulatory framework may appear to give it a far greater level of discretion than that of the AER. However, the Commerce Commission effectively assumes the roles of the AEMC and the AER and, in practice, the Commission has set itself rules that constrain it in ways similar to the constraints on the AER. However, it must also be borne in mind that the New Zealand framework remains largely untested.

Our consultants have also concluded that, although on the surface the UK regulatory regime may appear to provide Ofgem with considerable discretion that is not available to the AER, in practice the extent to which Ofgem may exercise unguided discretion is heavily constrained by the ability of NSPs to reject price control proposals and initiate a wide ranging merits review process.   Furthermore, even though Ofgem effectively assumes the roles of both the AEMC and the AER, it has set out and documented its approach to regulation. This documentation makes it clear that Ofgem's assessment of required expenditure will be predominately based upon a proposal, in the form of a business plan, put forward by the regulated entity.

In regard to the United States, they have noted that, although there is no one system of regulation, it does have as a strong foundation the filing of evidence (effectively, a regulatory submission) to support a 'rate case' (effectively, a request for adjusted tariffs). As a matter of principle, either a service provider or a customer representative can initiate a rate case but in practice the tendency for prices to rise over time means that rate cases are generally initiated by the service provider.

Importantly, the initial filing with the relevant regulatory body becomes the reference point for the subsequent process of reviewing and testing the evidence put before it, including evidence put by user groups or other interested parties. That process takes place in a quasi-judicial setting, involving hearings, including the cross examination of expert and fact witnesses who have attested to the information submitted. Although these processes are in many respects different from those prevailing in the UK, New Zealand and Australia, it has as a fundamentally important characteristic the procedural weight given to material submitted by the service provider, as well as any other interested party. United States regulators are certainly not 'at large' to develop and apply their own methodologies for assessing and evaluating material put before them.

In summary, our consultants have concluded that international regulatory practice continues to place an NSP's proposal at the centre of analysis. In addition, given the scope for merits or judicial appeals, regulators have recognised that evidence based decision making is necessary for a stable and predictable regulatory framework. On that basis, there is no evidence to suggest that either the principle of guided discretion, or its application by the AER, implies that the original policy intent is no longer consistent with international best practice.

4.3 Capital expenditure incentives and related issues

The promotion of efficient capital expenditure decisions is one of the most fundamental and complex areas of design in the regulation of long-lived monopoly infrastructure. The efficient timing, delivery and form of capital expenditure to meet expected demand is challenging task for network businesses exposed to continuous new information, and impossible to establish on an *ex ante* basis for any regulatory body. Critically, analysis of capital expenditure patterns needs to recognize that there a multiple and often interacting exogenous causes of capital expenditure variations from individual point in time estimates embedded in either regulatory proposals or determinations. This should induce caution in regulatory design and pricing decisions being based simple 'binary' classifications of outturn expenditure as either 'under' or 'overspends'.

The network sector therefore supports the use of incentive-based mechanisms to promote continuous, effective and stable financial incentives for efficient expenditure. To this end, the network sector considers that the development and implementation of a symmetrical, principles-based capital expenditure incentive mechanism. This should be feasible, with appropriate adaptions, across both electricity transmission and distribution rules.

This approach is far preferable to a reversion of the regulatory framework towards provision of *ex post* prudence assessment processes. These approaches involve intractable design and implementation issues surrounding later decision-makers with information unavailable to the network business being In a position to retrospectively strand prudent investments. The disadvantages of *ex post* prudency tests include a capacity to distort efficient investment, and increase regulatory risk.

4.4 Answers to specific questions

Question 7 - In what circumstances would an NSP need to spend more than its allowance under the NER?

It is important to emphasise that, putting aside the regulatory framework, NSPs will always be constrained in the amount of capital that they are able, and willing, to commit to the business during a regulatory period. In the short run, internal cash flow constraints arising from the need to maintain credit ratings and debt covenants place limits on network business' investment decisions. In addition, whether under private or public ownership, NSPs' shareholders always have alternative uses for capital, and this places a further constraint on ability for NSPs to commit additional expenditure during a period. The implication of these real world constraints is that spending in excess of amounts determined through a regulatory determination is subject to significant checks and balances.

Further, the current incentives in the framework work such that an NSP is penalised for operating expenditure that occurs in excess of forecasts over the regulatory period. While the size of the penalty may decline over the duration of the period, NSPs still need to bear the financing cost of any expenditure that occurs in excess of forecast amounts. ENA notes that the presence of incentives to avoid spending more than forecast amounts is acknowledged by the AEMC in its Directions Paper. Specifically, the AEMC states that the NER does not create an incentive for NSPs to spend more than their allowance during the regulatory period.

The premise for the Commission's question on the circumstances under which an NSP would need to spend more than its allowance appears to be a view that any expenditure in excess of an allowance is inefficient. Indeed, this appears to be a fundamental tenent of the AER's proposal for an asymmetric incentive scheme that arbitrarily limits the recovery of expenditure in excess of a forecast. However, the more important question is whether or not expenditure is efficient (rather than greater or less than a forecast allowance), and whether the regulatory framework needs amendment to give further emphasis to efficiency. There are many circumstances where the efficient level of expenditure can turn out to be materially different from the forecast, even if the forecast itself reflected an efficient level at that time. Given this, Rule changes designed simply to encourage NSPs to spend only the approved forecast would most likely encourage inefficient behaviour.

At a high-level, there are three key reasons why actual expenditure may exceed regulatory allowances. These include:

- regulatory error;
- the need to meet additional obligations; and/or
- service incentive schemes.

Regulatory error

One of the most important factors influencing whether outturn expenditure aligns with forecast is the affect of regulatory error on the forecast itself. Businesses put forward proposals of the expenditure amounts they consider are necessary to meet its regulatory and other obligations during a regulatory period. However, it has been noted in previous submissions that the AER has often made significant cuts to these forecasts. That process may itself give rise to an unreasonably low expenditure allowance. While an NSP would still have the incentive to minimise the extent that it spends in excess of its regulatory allowance, reliability and service standards as well as other regulatory obligations may nevertheless require expenditure to be made in excess of a forecast allowance. In addition, the risk of regulatory allowances being inefficiently low would markedly increase if the AER's proposed Rule changes were accepted and it was able to have considerably less emphasis to the NSP's proposed operating and capital expenditure allowances.

Additional outputs requirements and obligations

NSPs may be required to incur expenditure in excess of approved forecast amounts in order to serve additional outputs or to meet obligations than are not reflected in the approved forecast. The purpose of the expenditure forecast is to set an estimate of efficient future expenditure levels in order to set prices. An important point to note is that this forecast may be established some 5-7 years out from the time of actually making the investment decision. Further, it is based upon the information available to the NSP at the time of making the forecast, for the purposes of the regulatory determination process. However, this forecast is not expected to be a precise determination of the actual expenditure necessary during the regulatory period. Indeed, by its nature, forecasting is a prediction about the future that may or may not eventuate in reality. The forecast in this circumstance is seeking to predict expected outcomes up to seven years in advance. However, factors such as changes in the local and global economy and demand, changes in service standard obligations, or other policy initiatives can have a significant influence on either the cost of a particular investment, its requirement, or its timing. Where this is the case it also implies that outturn expenditure will be different, and potentially greater, than the amount that was forecast several years previously.

It is noted that the AEMC has identified that 'uncertainty measures' such as capital expenditure re-openers, contingent projects and pass throughs exist in order to address some of the impacts of changes to regulatory obligations or other factors. There are three reasons, however, why these mechanisms have not been effective in taking away the risks associated with changes to the output requirements or obligations of an NSP:

- First, to date uncertainty mechanisms have not applied in full, or at all, to NSPs. Therefore, historically at least, some of the observed differences between forecast and actual expenditure have reflected material changes in regulatory obligations that have not been compensated through pass through arrangements or other mechanisms. A specific example of this is the case for Energex , where the QCA provided Energex with a capex re-opener of $720 million in its 2005 final determination. In assessing Energex's application for the $720 million capex pass-through, Worley Parson's (the QCA's consultant) noted that Energex had more EDSD compliant and necessary expenditure than that included in the pass-through application; but had limited its application to the $720 million maximum value that the QCA had set in the final determination.[21]

- Second, even where uncertainty mechanisms are applied properly to all NSPs, it is impractical, and inefficient, for those mechanisms to shield NSPs from all output related risk. Completely shielding NSPs from these risks would potentially reduce the incentive on NSPs to find innovative and low cost solutions to the challenges of output related risk. This point was recognised by the AEMC when it developed the pass through and contingent projects arrangements in the Rules, in addition to

[21] QCA *Energex Application for Capital Expenditure Cost Pass-through*, Final Decision, March 2007, p.9

ensuring that the administrative costs associated with their application are only incurred in material circumstances.

- The individual uncertainty regime measures, including the threshold and conditions, may not be sufficiently flexible to accommodate the circumstances and/or unforeseen projects that may be required during a regulatory period. For example:

    - o Capex re-openers – were designed as a ‘shipwreck clause’ and have a threshold of >5% RAB. Hence the re-opener is not amenable to activation for typical projects which may arise during a regulatory period;

    - o Contingent projects – the NSP is limited to the contingent projects approved by the AER at the time of a regulatory determination, with a threshold of $10 million or 5% MAR (whichever is the greater). NSPs cannot activate this scheme for any other projects during the regulatory period;

    - o Pass throughs – these apply only to a limited number of pre-defined circumstances meaning that there is considerable scope that significant high cost events occur during a regulatory period that are not captured through this mechanism. This is particularly the case for transmission where there is no scope at present to propose pass through events at the time of a determination.[22]

Uncertainty mechanisms also do not facilitate a timely response to customer needs. Uncertainty mechanisms tend to involve particularly onerous and intrusive review by the AER at the time an application is made by an NSP. NSPs make hundreds of network investment and operational decisions during a regulatory period. In particular for distribution, these decisions are best made as close as possible to the time of implementation. Therefore, it is not practical for NSPs to undergo detailed and intrusive review mechanisms prior to those decisions being implemented.

Service incentive schemes

Another critical reason why outturn expenditure may be greater than forecast amounts is the effect of service incentive schemes such as the s-factor. These schemes are designed to provide an incentive for NSPs to incur more expenditure for service improvements when customers value that improvement. Consistent with this, approved forecast expenditure allowances do not include amounts associated with making service improvements in excess of minimum requirements. This is because these levels of expenditure are discretionary and would only be undertaken where the perceived payoffs through the service incentive scheme are greater than the cost. The consequence, however, is that if these schemes are driving desirable behaviours from NSPs some spending in excess of forecast amounts is expected, and indeed, desired by customers.

Given there are a number of reasons that make it entirely appropriate for an NSP to spend in excess of forecast, the AER’s proposal to use the RAB roll-in mechanism to give effect capital expenditure incentives involves a significant risk of dissuading otherwise efficient investment. The AER’s proposal establishes an asymmetric incentive against expenditure in excess of forecasts. Ultimately, the negative impact on incentives for efficient investment would be to the detriment of customers.

[22] ENA notes that there is presently a Rule change before the AEMC to address this matter for transmission. See http://aemc.gov.au/Electricity/Rule-changes/Open/Cost-pass-through-arrangements-for-network-service-providers.html

Question 8: What is the best option for dealing with the capex incentive issues identified in this paper?

The Commission's view is that the Rules do not involve any incentive for NSPs to spend inefficiently, whether above or below their capital expenditure allowance. Nevertheless, the Commission observes that the incentives for expenditure to be efficient are strongest at the beginning of a regulatory period and decline over the period. NSPs concur with this diagnosis. The Commission considers that this creates a risk of:

- sub-optimal timing of investments and
- the power of the capital expenditure incentive changing over the course of the regulatory period relative to operating expenditure incentives.

The Commission is also concerned that there is no 'supervision' of capital expenditure incurred in excess of forecast amounts, since all actual expenditure is automatically rolled into the RAB. Given the concerns of the Commission, and agreement amongst stakeholders that there are issues to be resolved for capital expenditure incentives, the current framework, or at least its application, needs to be revisited.

Application of financial incentives preferred

By way of overarching principle, NSPs believe that appropriate and sustainable financial incentives are the best mechanism for encouraging expenditure behaviour that is consistent with the NEO. Where practicable and well-designed incentive arrangements are in place, they can be expected to lead to better outcomes than would be achieved by direct regulatory intervention, such as any process involving the AER reviewing and forming a view on the efficiency of operational or investment decisions.
Given the benefits associated with financial incentives, the best solution to overcoming the shortcomings of the existing framework is to amend the Rules so as (for transmission) to provide for (or in the case of distribution, give effect to) a symmetric efficiency benefits sharing scheme (EBSS) for capital expenditure. Implementing such a scheme has the benefit of:

- strengthening the incentives on NSPs to minimise capital expenditure in the later years of the regulatory period, i.e. a continuous scheme
- allowing incentives between capital and operating expenditure to be balanced so that efficient choices between the two forms of expenditure are made when they are substitutes, and
- providing a symmetrical incentive so that the incentive applies not only to capital expenditure in excess of the regulatory allowance but also to all capital expenditure within an NSP's allowance.

Introducing a continuous incentive for capital expenditure through an EBSS would also negate the need for any ex-post assessment of the efficiency of capital expenditure. Rather, incentives could be relied upon to encourage NSPs to behave in ways that are consistent with the promotion of the NEO. However, NSPs' recognise that important implementation issues in applying an EBSS to capital expenditure need to be addressed. Perhaps the most challenging is the need for measures to avoid creating incentives for NSPs to inefficiently defer capital expenditure from one regulatory period to the next. Similar continuous incentive schemes apply in other jurisdictions, and in these jurisdictions mechanisms exist to address the deferral incentive. Notwithstanding, it is a complex matter and so is best suited to a process managed by the AER through the development of guidelines – such as have been put in place for the EBSS – rather than through the AEMC Rule change process.

While ENA considers that the development and trial of an EBSS to capital expenditure is the first best solution to addressing known issues with the present incentives framework, if it proves impracticable to address the concerns regarding the potential for inefficient deferral of capex, the AER should retain the discretion not to introduce a capital expenditure EBSS. While this would be a second best outcome, the discretion to not implement an EBSS on capital expenditure in this circumstance would be preferable to an asymmetric scheme. An asymmetric scheme would be inappropriate primarily because it would not change the incentive on NSPs that expect to under-spend against the ex-ante forecast of capital expenditure, and so would not in fact address the challenges the Commission has identified.

The ENA has asked its experts, in light of their previous report on capital expenditure incentives, to recommend a set of criteria to inform the implementation and design of an EBSS for capital expenditure. On this basis, in the JER on Capital and Operating Expenditure, the following statement and criteria were set out:

> *"The criteria have also been developed so that they could apply equally to transmission and distribution sectors. However, it is assumed that a separate Chapter 6 and 6A will remain and hence a separate scheme would be developed for transmission and distribution. It is envisaged that the resulting schemes as implemented would vary materially between transmission and distribution sectors, reflecting the differences in the technology / cost structure, services provided and regulatory obligations between the sectors. A criterion is included at the end of the list to encourage industry specific factors to be taken into account.*
>
> *We consider that the following criteria are required for the design of a best practice EBSS for capital expenditure:*
>
> 1. *The AER would have the discretion, but not the requirement, to implement an efficiency benefits sharing scheme for capital expenditure. If it decided to introduce such a scheme, the scheme would be required to meet the remaining criteria set out below*
> 2. *Objective for the scheme is to share the benefits of efficiency gains in a manner that best promotes the National Electricity Objective*
> 3. *Requirement for the scheme to measure efficiency gains by comparing actual expenditure against the ex-ante forecasts, except where adjustments to actual or forecasts are authorised by this Rule*
> 4. *Requirement that the method for identifying and rewarding / penalising efficiency gains provide, as far as practicable:*
>   - A. *A continuous incentive, defined as an incentive that is equal in each year, and*
>   - B. *Rewards for improvements and penalties for a decline in efficiency, and where improvement or decline of equal size (in absolute terms) would accrue the same reward or penalty (in absolute terms)*
> 5. *Requirement for the scheme to specify, or define a method for specifying, for a particular NSP, an appropriate incentive power for the scheme, having regard to:*
>   - A. *The desirability of generating a net benefit to customers*
>   - B. *The desirability of the scheme, in combination with other incentive arrangements and regulatory obligations, providing NSPs with an incentive to act in a manner that is consistent with the NEO (including to provide an optimal level of service and to minimise the total cost of this), taking account of:*
>   - i. *The effect of the method used to update the RAB over time on the incentives relating to capital expenditure, including the choice between forecast and actual depreciation*
>   - ii. *The incentives relating to operating expenditure*

iii. The breadth of financial incentives related to service performance applying to NSPs or class of NSPs and the power of the incentives in such schemes

iv. The breadth of the regulatory obligations (including service standards) applying to NSPs or class of NSPs, and

C. The residual risk that is created by the scheme for NSPs after considering the effect of mechanisms contemplated in clause 5.

6. Requirement to implement measures within the scheme to the extent practicable to reduce the impact on NSPs and customers of events that are not within the full control of NSPs, including by:

A. Making adjustments to the forecast or actual expenditure for categories of expenditure to reflect, to the extent practicable, the events that occurred during a regulatory period, provided the method for doing so is defined in advance

B. Considering whether certain classes of projects should be excluded from the scheme, and

C. Considering whether a quantitative limit should be set for the impact on NSPs and customers of the effect of differences between forecast and actual expenditure

7. Authorise adjustments to the forecast expenditure, actual expenditure or to the calculated EBSS amounts where necessary to ensure that the calculated EBSS amounts are consistent, to the extent practicable, with rewarding or penalising NSPs for the actual change in efficiency, provided that the method for making such adjustments is defined in advance of the regulatory period to which the expenditure relates

8. Requirement to consider the implementation costs of the scheme and to factor this into the design of the scheme

9. Specification that parameters or values under the scheme may vary between NSPs or classes of NSPs over time."

Ex-post prudence tests create additional risk without additional benefit

An ex post prudency test is intended to promote efficiency by giving forewarning that investment that is deemed not to be prudent or efficient will not be rolled into the RAB. When designed and applied properly, an ex-post prudency test should not provide any additional incentives compared to a well designed ex ante regime. The net effect, therefore, is that there would be no additional promotion of efficiency under this approach.

However, it is considerably difficult to design and apply an ex-post prudence test. This is due to factors such as the difficulty of limiting information considered by the regulator to only information that a prudent NSP would have used at the time an investment was made and establishing what projects should be subject to review so to avoid the cost and time associated with reviewing all investments undertaken by an NSP.

Therefore, the strong possibility that the test is not well designed or applied creates substantial risk for NSPs that otherwise prudent expenditure is not rolled into the RAB. Its likely consequence is to distort the incentives of the ex ante regime so that network businesses may avoid otherwise efficient expenditure. This may particularly be the case where there is some short term discretion associated with a project, such as investments that renew existing plant in poor condition. There are also a range of fundamental implementation issues with ex post mechanisms that have not been satisfactorily overcome in any schemes currently in use. Examples of these include whether all project are 'opened up' to ex post review, or whether only material projects or projects undertaken most recently are re-examined. Further, it is unclear how an ex post mechanism can adequately accommodate consideration of projects whose nature were not conceived at the time of the prior reviews, and for which, therefore, no 'expected' level of expenditure arises.

It is relevant to note that in the NEM the ACCC, AER and AEMC have each considered and rejected the use of an ex-post prudence test. For instance in the background paper for the Statement of Regulatory Principles the ACCC identified the following disadvantaged of the ex-post approach:[23]

> *"In the draft SRP the disadvantages of ex post assessment were discussed. Specifically, two key disadvantages were identified:*
>
> 1. *It creates uncertainty for investors that, after having invested, the ACCC could decide that the investment was not prudent and hence disallow recovery of the investment cost in regulated charges.*
> 2. *It is not clear that the threat of ex post prudency assessment provides effective efficiency incentives. If TNSPs do not think that the threat is credible, then they have no economic incentive to select the most efficient investment and develop assets at least cost. On the other hand, if they do think that the threat is credible, they may be inclined to inefficiently under-invest for fear that the ACCC will come to a different conclusion on the prudency of the investment they make."*

The AEMC when commenting on the application of an ex-post prudency test in the development of the current chapter 6A Rules was particularly concerned about the impact such a test would have on ex-ante incentives:[24]

> *"Taking into account the need to ensure the regime provides appropriate incentives for TNSPs to invest in sufficient capacity to maintain service levels amid dynamic demand conditions, the Commission maintains the view that it is not appropriate for an overspend of capital to be subject to a prudency review. If the AER was given the scope to exclude capital overspend from the RAB the power of the incentive to efficiently incur capital expenditure costs that were not foreseen at the time of the applicable regulatory determination would be reduced."*

Finally, the AER in the Rule change proposal that the AEMC is presently considering indicated that it given the application of an ex-post prudence test further consideration and rejected it as an effective tool. The AER rejected an ex-post prudence test because it was concerned that it may add to regulatory risk.[25]

ENA notes in addition, that the focus to date of an ex-post prudence test has been on removing expenditure deemed to be inefficient from the RAB. However, a legitimate alternative design of an ex-post prudence test may see an NSP's revenue allowance increase following a review. For instance, if an amount of expenditure in excess of the approved forecast was deemed to be efficient, a regulator may decide to allow that NSP to claw back any amount of foregone return on, and return of, the investment. Such a scenario would be feasible in a circumstance where the regulator determined an inappropriately low forecast for expenditure.

Given that the best outcome of a regime that involves an ex post prudency test is no change relative to a regime with well designed ex ante incentives, and the risk of negative outcomes compared to the counterfactual, the ENA believes that the first best solution is not to provide for an ex post prudence test of capital investments in the NEM. To the extent that there are problems with the current incentives for capital expenditure efficiency, these should be addressed through improvements to the ex ante regime, such as the implementation of an EBSS to capital expenditure, rather than through the addition of an ex post prudency test, which itself is likely to compromise incentives to invest efficiently.

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[23] ACCC *Decision, Statement of principles for the regulation of electricity transmission revenues – background paper,* 8 December 2004, p.44.
[24] AEMC *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18,* 16 November 2006, p.99.
[25] AER Rule Change Proposal, p. 43.

Question 9: How does using actual or forecast depreciation to determine the RAB affect a NSP's behaviour?

The Commission identified in its Directions Paper that it is interested in more detail as to how using actual or forecast depreciation affects a NSP's behaviour. The Commission has referred to two types of 'behaviour' that may be affected through the use of either forecast or actual depreciation:

- A bias against short lived assets, and
- The potential that actual depreciation will provide an incentive for NSPs to inflate their forecast.

The Joint Expert Report on capital expenditure incentives attached to the previous ENA submission provided some analysis of the impact of the relative power of the incentive scheme where actual depreciation was applied. Table 2.1 in that report, replicated below with the addition of values related to assets with a 5 year asset life, demonstrates that the penalty from spending more on assets with a short economic life is inappropriately large compared to longer lived assets. This is because the "penalty" from one extra unit of expenditure increases as the asset age falls.

The impact of this penalty is to create a relative disincentive for NSPs to incur additional expenditure on assets with a short economic life relative to those with a longer economic life. This incentive particularly affects investments in IT infrastructure and other 'smarter' technologies; which would be expected to become more pronounced in future years given the developments of smart meters and smart grids. While these assets may make up only a small proportion of the total asset base for an NSP, they have the capability of being used as a substitute for longer lived network assets, or at least provide an NSP with additional information that allows it to make a better decision about when network augmentation or asset replacement is required. It follows that the application of actual depreciation is likely to lead sub-optimal investments in innovative technologies and potentially an increased reliance on network solutions with a long asset life.

	Current Regulatory Period				
Life of Asset	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
5 years	84.9%	67.6%	47.9%	25.5%	0.0%
7 years	67.7%	53.8%	38.0%	20.1%	0.0%
20 years	39.7%	31.2%	21.9%	11.5%	0.0%
40 years	32.1%	25.2%	17.5%	9.1%	0.0%
Depreciation excluded	24.6%	19.1%	13.2%	6.8%	0.0%

The ENA recognises that an incentive to submit inflated forecasts is inevitable in a regime that provides rewards or penalties for differences in expenditure from forecast amounts. However, the comprehensive assessment by the AER of NSP's expenditure forecasts, and scrutiny of proposals by stakeholders, is the appropriate mechanism for mitigating against inflated expenditure forecasts.

Importantly, reducing the power of incentives should not be seen as an appropriate response to concerns in relation to inflated forecasts of expenditure. The priority of an incentive scheme should be to ensure that *actual* expenditure is efficient. This means that, over time, NSPs will have the incentive to reveal the efficient costs of provision, assuming the scheme has well calibrated incentives for achieving cost efficiency gains.

Although reducing the power of the incentive is not generally the appropriate response to concerns about inflated forecasts, other factors that mean that the application of actual depreciation (the original reasoning for which was to strengthen incentives) is not preferred. The use of actual depreciation in the RAB roll forward process creates a bias against short lived assets and does not resolve the issue of the strength of the incentive declining over the regulatory period. For this reason, ENA reiterates its support for the application of the EBSS to capital expenditure as the preferred approach to providing well calibrated incentives.

Question 10 – The Commission seeks submissions from retailers on any other options for minimizing the impact of capex reopeners.

This question is not being addressed by ENA.

Question 11: More extensive use of the uncertainty regimes means regulatory arrangements more closely resemble commercial contracts, is this appropriate?

It is not clear how the increased use of uncertainty regimes would more closely resemble commercial contracts. In the Directions Paper the Commission notes that under commercial arrangements in a competitive market, businesses can choose whether or not they provide a service and the conditions and price under which such services are provided. It is acknowledged by the Commission that this same choice does not exist for regulated network services. However, the costs that are affected by such uncertainty measures would in most cases relate to projects over which NSPs have limited discretion and the price and conditions for providing the services are regulated. Therefore, the flexibility for NSPs, which would otherwise be accommodated in a commercial contract through either the price or whether the service is provided at all, is not available.

Even though contingent projects and pass through arrangements will often relate to obligations on NSPs, there is nevertheless a limit to the extent that these mechanisms will remove exposure for NSPs from exogenous events.

Pass through arrangements typically apply to a narrowly defined class of events. In addition, either the Rules, in the case of transmission, or the AER, in the case of distribution, require that a materiality threshold be met before an amount can be treated as a pass through. As a consequence, there will inevitably be costs that NSPs will be exposed to throughout a regulatory period over which they will be unable to recover the costs of through prices. In addition, particularly for pass through events, there is considerable uncertainty about whether the framework accommodates the circumstances and / or unforeseen projects that causes additional costs to be incurred.

With respect to contingent projects, these are, to a large extent, only sensible for very large and uncertain projects. They require identifying the potential project several years in advance of it being required and a defined trigger event for the mechanism to be applied. Therefore, it is difficult for the mechanism to apply to much of the demand-related related expenditure for transmission or the program nature of distribution investments. For transmission this means that it is inevitable that considerable demand risk will remain with TNSPS, while for distribution it means that there is very limited projects upon which the scheme can apply. Further, in the case of transmission, the experience to date has been that the AER has applied the contingent projects mechanism in a rigid and narrow fashion. This means that it has been difficult to have projects defined as contingent projects.

It is also relevant to note that the contingent projects framework is only effective for projects that can be clearly defined with an appropriate trigger up front. However, during the regulatory period as more information is revealed, or circumstances change, new project requirements may become evident. These projects that are revealed only during the regulatory period cannot be accommodated by the contingent projects framework meaning NSPs will be fully exposed to their costs.

Capital expenditure re-openers are another form of uncertainty mechanism. However, this mechanism was designed with an intent to operate as a ‘shipwreck’ provision. Therefore, this mechanism is only triggered in extremely limited circumstances and when the impact on cost is substantial (greater than 5 per cent of the regulatory asset base). Therefore, this mechanism would not apply to the vast majority of events that may lead to additional costs being incurred by an NSP.

A further important limitation of uncertainty mechanisms is that they are not subject to the same merits review mechanisms as the AER’s assessment in a determination. Therefore, if the AER makes a decision in error when assessing either a pass through or contingent projects application NSPs are fully exposed to the consequences of this error with only limited avenue for judicial review of a decision. This gap in the framework increases the risk for NSPs from relying upon uncertainty mechanisms to manage uncertain cost outcomes.

Question 12: To what extent would stronger capex incentives, through an EBSS for example, deal with incentives for NSPs to inefficiently change its capitalisation policy during a regulatory control period?

The Commission has identified an issue in relation to changes made by NSPs in their capitalisation policies during a regulatory period. The Commission considers that the likely cause is an imbalance between the incentives applying to operating and capital expenditure.

The current EBSS that operates for distribution and transmission businesses already includes a provision that removes the potential for NSPs to make changes to their capitalisation policy in order to distort otherwise efficient outcomes. The AER requires that an NSP provide a detailed description of any changes in capitalisation policies that have arisen during the regulatory period or that are proposed to apply in the next regulatory period. If the AER is not satisfied that a change in capitalisation policy is appropriate it has the discretion to adjust the forecast operating expenditure allowance to remove any advantage for the NSP due to this change.

Notwithstanding the current arrangement in the design of an EBSS, while an EBSS on capital expenditure would reduce the incentive to capitalise operating expenditure, there may still be scope for ‘gains’ to be made from reclassifying operating expenditure as capital expenditure. Therefore, it is appropriate that the AER should retain the ability to calculate operating and capital expenditure efficiency gains in a manner that removes the effect of changes to the classification of expenditure.

Question 13: How, and to what extent, does the incentive for a NSP to overspend or underspend vary depending on whether it uses a related party or not having regard to the other incentives for efficient capex, including the scope for the AER to determine efficient capex at the regulatory determination?

This question is not being addressed by ENA.

Question 14: To what degree would a parent company of a NSP be better off if related party margins, that are higher than those allowed for by the AER in the regulatory determination, are due to genuine higher costs?

This question is not being addressed by ENA.

Question 15: Should the AER be given the power to develop and implement pilot or test incentive schemes within a controlled environment?

See below a consolidated response to Question 16.

Question 16: What limits should be placed on the scheme?

The AER has proposed that the Rules be amended so that it has the power to introduce new incentive schemes when it considers that there are benefits from doing so. The Commission suggests there might be value in additional incentive schemes being developed in Australia from time to time, and asks whether the current Rule change process is too big a hurdle to introduce new incentive schemes.

The Commission also recognises in its analysis that there is a risk that new incentive schemes could be introduced that lead to unexpected and perhaps unwelcome outcomes. ENA agrees with this assessment and so does not support the conferring of a broad power for the AER to develop new incentive schemes. Giving the AER such a power could allow the AER to bypass criteria and protections that apply to specific incentive schemes.

Although there are considerable risks associated with a broad based power to introduce incentive arrangements, there are, nevertheless, benefits in ensuring that the incentives framework remains innovative and properly aligns the incentives for NSPs with outcomes that are desirable for customers. On that basis, there is likely to be some merit in allowing the AER to develop small scale pilot or test schemes as appropriate.

The principal problem with a broad based power to introduce new incentive schemes is that it may lead to the AER ignoring important criteria and principles. The impact of this could be a considerable increase in the costs and risks faced by NSPs without a corresponding benefit for customers. On that basis, the limits that are placed on any scheme introduced should serve to ensure that the costs and risks for NSPs are minimised while still allowing for meaningful results to be obtained. The relevant factors that would need to be taken into consideration may include:

- Limiting the revenue at risk to only small amounts or paper trials;
- Requiring that NSPs are involved in the design of the scheme;
- Requiring that an NSP agree to participate in the scheme before it is trialed; and
- Limiting the operation of the scheme to only parts of an NSPs operations, e.g. to certain regions or certain classes of customers

Question 17: Should the concept of compensation for consumers for use of shared assets be applied to transmission, as well as distribution?

ENA notes that the matter of compensation for consumers was raised in the AER's proposed Rule change in the context of distribution assets only. However, given that this is a new matter for transmission that did not form part of the AER's Rule change proposal, ENA refers the Commission to Grid Australia's separate submission in response to the Directions Paper.

Question 18: Stakeholders have suggested use of assets for alternative control services should be excluded from the uses for which consumers should receive compensation. Are there any other examples of such uses?

To the extent that assets included in the RAB are used to deliver alternative control services (and the users of the alternative control services are charged for use of these assets), it is appropriate that that network customers should receive some compensation. Under the transitional arrangements for Queensland, a small proportion of non-system assets in the RAB are used to provide alternative control services and a revenue adjustment is recognised in the building block for standard control services for ENERGEX and Ergon Energy.

Question 19: What are the appropriate guiding principles allocating compensation arising from sharing assets between regulated and unregulated services?

The ENA supports its members pursuing alternative uses for electricity system assets as it enhances societal welfare by supporting both productive and allocative efficiency. Therefore, the ENA believes that the NER should provide incentives for NSPs to use assets for delivery of other services which earn additional revenue; this supports the National Electricity Objective (NEO). The ENA also believes that electricity customers should share in benefits associated with distribution system assets; the NEO promotes the long term interests of customers, which the ENA believes should preclude shareholders capturing all the benefits.

At the same time, the incentives for NSPs to pursue alternative uses and thereby realise associated NEO benefit outcomes are heavily dependent on the ratio of benefit sharing between NSPs and electricity customers. Therefore, the sharing of benefits arising from multiple uses of electricity network assets between electricity customers and NSPs should be consistent with the following principles:

- NSPs should be incentivised to pursue alternative use network services by being permitted to retain a share of benefits from these services;
- Benefits should be defined as incremental revenue from alternative uses net of all incremental costs including avoidable costs, tax, the cost of risk, and a reasonable margin associated with the non-regulated alternative use service;
- Arrangements for implementing benefits sharing should:
    - Recognise legacy arrangements and the maturity of the market for alternative uses
    - Be administratively simple
    - Be proportionate to the benefits.

This answer represents the developed views of ENA's electricity distribution members. Further details as to the applicability of these matters to the electricity transmission sector are set out in GridAustralia's separate response.

5. Capital and operating expenditure factors

The ENA considers that the capital and operating expenditure factors that have been termed ‘procedural’ have a very important role to play in the decision-making rule that the AER is required to apply when assessing capital and operating expenditure forecasts. Further, that these expenditure factors reflect clear policy decisions that were made in the drafting of Chapter 6 and Chapter 6A.

A key policy decision was the adoption of the “fit for purpose” framework, where the level of discretion given to the AER in accepting or rejecting an element of a service provider’s proposal would be defined by the Rules. In relation to the AER’s discretion to accept or reject a service provider’s forecast capital or operating expenditure amount, the relevant discretion or decision-making rule adopted was that if a service provider’s forecast was consistent with the requirements of the Rules, that the AER was required to accept that forecast. However, if the AER is not so satisfied, then the AER can determine the substitute forecast that it considers to be consistent with the requirements of the Rules.

The ENA submits that the decision-making rule that applies to capital and operating expenditure forecasts remains appropriate and therefore no removal or amendment to the capital and operating expenditure factors in this regard should be made.

Current National Electricity Rules

The capex factors are set out in clauses 6.5.7(e) and 6A.6.7(e) and the opex factors in clauses 6.5.6(e) and 6A.6.6(e) of the NER.

The capex and opex factors are matters which the AER must have regard in determining whether to approve a regulatory proposal.

The AER considers that the first three matters are procedural in nature and that they do not ‘substantively add to an assessment against the expenditure criteria’.[26] The first three expenditure factors require the AER to have regard to:

- information included in or accompanying the building block proposal;
- submissions received in the course of consulting on the building block proposal; and
- analysis undertaken by or for the AER and published before (or as part of, as is the case in transmission) the determination is made in its final form.

AEMC initial position

The AEMC’s initial position on the AER Rule change proposal is set out in summary below.[27]

- The opex and capex factors should not be exhaustive, but remain mandatory considerations.
- In respect of the ‘procedural’ matters currently included as the first three expenditure factors, those factors resemble more closely to the procedural requirements found in other places in the NER and it would be appropriate to move these as proposed by the AER.

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[26] Australian Energy Regulator, *Economic Regulation of Transmission and Distribution Network Service Providers: AER’s Proposed Changes to the National Electricity Rules – Rule Change Proposal*, September 2011, p 34 (**AER Rule Change Proposal**).
[27] AEMC *Directions Paper* (2012), p.32 -33.

- In respect of the requirement on the AER to consider analysis which it has published, that the NER be clarified to make it clear that there is an obligation on the AER to publish its analysis with its draft or final regulatory determinations, but no obligation to do so prior to this.

- The other expenditure criteria of demand forecasts and cost inputs are more significant to the AER's consideration of regulatory proposals than the first three expenditure factors. Therefore these should remain as criteria guiding the AER's assessment.

Response to AEMC initial position

The ENA takes issue with the AER's proposal in two main respects:

- first, the amendment of the requirement to 'have regard' to the information accompanying the service provider's proposal in assessing forecast capital and operating expenditure amounts and the removal of this amended requirement from the capital and operating expenditure factors to Part E; and

- second, the amendment of the obligation to have regard to analysis undertaken by or for the AER and published prior to the distribution determination being made in its final form (Chapter 6), or published prior to or as part of the final transmission determination (Chapter 6A)..

Before elaborating upon those issues, the ENA submits that it does not object to the AER's proposal that the capex and opex factors should not be exhaustive. The ENA does not consider that the current drafting does suggest that the factors are exhaustive, rather what the current drafting requires is that the AER must give all those factors that are listed fundamental weight in considering capex and opex forecasts, but that it is not precluded from considering other relevant matters. If the AEMC were minded to clarify this in the drafting, the ENA would not object to that.

Relocation and alteration of requirement to 'have regard' to service provider's proposal

Two points should be noted in relation to the AER's proposal to amend the factors relating to how the AER is to treat the information in the service provider's proposal when assessing forecast capital and operating expenditure amounts:

First, the requirement to give fundamental weight to information included in or accompanying the revenue proposal and submissions received in the course of consulting on the revenue proposal is removed. Under the AER's proposal, the AER is merely required to 'consider' this material.

Second, the requirement to have regard to the information mentioned above, together with the analysis undertaken by or for the AER in the context of making the specific decision on whether the AER is required to accept the forecast capex or opex amounts is removed. Under the AER's proposal, this information is only required to be considered, or, in the case of analysis undertaken by or for the AER, regard to be had to it, in the making of the final decision generally.

The requirement to 'have regard' means that the AER is *required* to have regard to each of the capex and opex factors, including: (a) the information included in or accompanying the revenue proposal; (b) submissions that have been received; and (c) analysis undertaken by or for the AER with the additional requirement in Chapter 6 that it has been published before the distribution determination is made in its final form. Those factors are <u>fundamental elements</u> in the decision making process of the AER in deciding whether or not it is satisfied that the forecast opex or capex amounts reasonably reflect the expenditure criteria and therefore, either must be accepted or rejected.[28]

[28] *Re Dr Ken Michael AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor* (2002) ATPR 41-886, [55].

That the opex and capex factors are fundamental elements in the decision making process is also supported by the original policy intention of the AEMC as referred to in the expert report prepared for the ENA. This report, authored by Geoff Swier, is entitled *Assessment of proposed changes to Regulatory Process and Practice* (which is Attachment F to this submission).[29] In particular it is noted in that report, that 'the original policy intent … [of] the AEMC sought to ensure transparency and certainty in the AER's decision making and to reduce the risk of regulatory error' and those principles underpin the inclusion of the procedural elements within the capex and opex factors.

The current Rules operate to require the AER to take the submissions and analysis into account and to 'give them weight as fundamental elements'[30] in assessing reasonableness of the NSP's expenditure forecasts. The factors listed are evidentiary matters which constrain and guide the judgment of the AER in accepting or rejecting the capex and opex forecasts. The ENA submits that having the expenditure factors as fundamental elements in that decision making process ensure that the AER cannot be at large to reject the NSP's forecast to replace it with its own forecast in the first instance. The removal of the first three expenditure factors would undermine that safeguard.

Given the importance of these forecasts in the determination of the overall regulated revenue amounts, and the requirement on the AER to accept those amounts where it is satisfied on the material before it that the forecasts are consistent with the requirements of the Rules, it is clearly appropriate that the AER be required to give that material weight as a fundamental element in making its decision. The current Rules process delivers certainty as to the matters which the AER must have regard in making its determination. In the annexed expert report on regulatory process and practice, the author considers that the AER's rational for the proposal – that there is ambiguity as to whether specific weight must be given and how that is to be balance with the other factors – is not justified, rather it appears to be a theoretical concern.[31]

The AER's proposed Rule would materially change the current position without proper or a sound justification. In the absence of any countervailing considerations as a basis for its proposal to relocate the first three expenditure factors transforming them from mandatory to permissive considerations within Part E of the Rules, that proposal should be rejected. A close inspection of the AER's proposed Rule change reveals an intention to fundamentally change the decision-making Rule that is not expressly referred to or discussed in the AER's supporting materials. Under the current Rules the AER is not directed in what material it should give primacy. It is clear that the AER can only substitute a forecast capex or opex value where it has formed a view that the NSPs forecast is not consistent with the Rule requirements.

Under the AER's proposal, the AER would be required to take into account the analysis undertaken by or on behalf of the AER, and merely consider the information in the NSPs proposals and written submissions. A possible legal interpretation of this drafting is that the AER would be required to give primacy to its analysis. This is a material shift from the current position in which the information in the NSP's proposal, the material in submissions by stakeholders, and the AER's analysis is to be treated equally. In summary, the requirement to give fundamental weight to information included in or accompanying the revenue proposal and submissions received in the course of consulting on the revenue proposal is removed. Under the AER's proposal, the AER is merely required to 'consider' this material.

The ENA submits that, particularly given the decision making rule that applies to capex and opex forecasts (that the AER must accept those forecasts where it is satisfied that the forecast amounts reasonably reflect the capital or operating expenditure criteria) it is appropriate that the AER give fundamental weight in making its decision to the material before it. The Australian Competition Tribunal (**Tribunal**) has affirmed the position that it is the material before the AER, and in particular the material submitted by the service provider, that will fundamentally determine whether the AER can be satisfied as to the service provider's capex and opex forecasts. The Tribunal has commented that it is the service

[29] Geoff Swier *Assessment of proposed changes to Regulatory Process and Practice – Expert Report prepared for the Energy Networks Association*, 16 April 2012 (**Attachment F**).
[30] *Re Dr Ken Michael AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor* (2002) ATPR 41-886, [55].
[31] Attachment F, pp 16 - 17.

provider's 'prime responsibility' to provide information to the AER for the AER to consider and evaluate.[32] The Tribunal has also stated that a service provider has a 'critical role to play' in providing information to the AER to assist the AER in making a decision which reflects the National Electricity Objective and the revenue and pricing principles.[33]

Removal of requirement to publish analysis undertaken by or for the AER

Under the AER's proposal, in assessing capital and operating expenditure forecasts, the AER is to have regard to analysis undertaken by or for the AER, as opposed to having been undertaken and published. This consideration is more relevant to Chapter 6, as in Chapter 6A, the requirement is expressed in a different form requiring analysis undertaken by or for the AER to be published prior to or as part of the draft decision or the final decision (as the case may be).

The ENA considers that it would be inappropriate for any amendment to be made to the Rules to suggest that the AER is not required to make available, at a minimum to the service provider, material that it will rely on in making its final decision prior to the final decision being made. The ENA considers that the AER must make available to the service provider, and where possible, other stakeholders, all analysis that is material to the making of its final decision prior to that final decision being made in order that the material can be responded to. This is consistent with principles of good regulatory practice and procedural fairness which are principles embodied in section 16(1) of the NEL, which provides:

> The AER must, in performing or exercising an AER economic regulatory function or power—...
>
> (b) if the function or power performed or exercised by the AER relates to the making of a distribution determination or transmission determination, ensure that the regulated network service provider to whom the determination will apply, any affected Registered participant and, if AEMO is affected by the determination, AEMO, are, in accordance with the Rules—
>
> (i) informed of material issues under consideration by the AER; and
>
> (ii) given a reasonable opportunity to make submissions in respect of that determination before it is made.

The AEMC's proposal in its Directions Paper that the Rules should be clarified to make it clear that there is an obligation on the AER to publish its analysis with its draft or final regulatory determinations, but no obligation to do so prior to this, risks inconsistency with the requirements in section 16(1) of the NEL. The ENA considers that that the AEMC should signal in its draft Rule determination that it is best regulatory practice for the AER to, as far as practicable, publish and consult on any analysis on which it is intending to rely upon as part of its draft or final determination. This would clarify the position of the Rules with respect to expectations from the industry of the AER in exercising its decision making functions. More specifically, exposing analysis and reasoning to public scrutiny allows its probative value to be properly tested, and ensures that only the most robust analysis and evidence is relied upon in making a determination.

The ENA also strongly disagrees with the AEMC's initial view that scrutiny of material relied on in the final regulatory determination by the AER which was not relied on for the draft determination (and not published by the AER, or the subject of submissions) would be through merits review.[34] Not only would such a process be highly inefficient and costly, but the limited form of merits review, which involves parties only being permitted to rely on material submitted to the AER as part of the determination process to establish error, would mean that the relevant party seeking review of the AER's decision would only being able to respond to the material that the AER had made available with its final decision. In this regard, access to merits review cannot be (and should not be) a substitute for the AER exposing its reasoning prior to a final decision.

[32] *Application by Ergon Energy Corporation Limited* [2010] ACompT 6, [49].
[33] *Application by Ergon Energy Corporation Limited* [2010] ACompT 6, [50].
[34] AEMC *Directions Paper* (2012), p.32

The ENA's December 2011 submission noted that the AER had not identified any instances of where the requirement to publish or to otherwise make available analysis of material relied upon in the making of the final decision had caused it difficulty.[35] The ENA's review of recent decisions did not highlight any issue with the requirement for publication and transparency of analysis. In fact, when the AER has undertaken further analysis in circumstances where it has considered a material shift in position between the draft and final decision, it has had sufficient time to publish and consult on this shift prior to making its determination.[36] Furthermore, the review of decisions also revealed occasions whereby the AER relied upon new analysis and evidence in relation to gamma (the assumed utilisation of imputation credits) which were not published or consulted on prior to the final decision being made. On review of the AER's gamma decision, the Tribunal ultimately found errors in the AER's interpretation of these expert reports.[37] Had the AER consulted prior to making its decision on the basis of these expert reports, these errors of interpretation may have been identified prior to the determination.

The ENA submits that the experience so far demonstrates the benefits of transparency in terms of exposing errors or deficiencies in reasoning and ensuring that only the most probative evidence is relied on in decision making. As the requirement for transparency does not appear to have caused difficulties so far (the AER only identifies *potential* for problems in the future), the ENA considers that an evidential basis for amendment to the Rules in the manner proposed by the AER has not been established.

As noted above, the ENA would not object if the AEMC thought it desirable to clarify that the capex and opex factors are not exhaustive and the AER can take into account additional relevant matters. This would make the position clear in Chapter 6 that the AER can consider analysis it has undertaken but which has not been published. Of course this would always be subject to the requirement in section 16 of the NEL. That said, as the AER does not currently publish all of the analysis that it has undertaken prior to making a final distribution determination, it is not clear that such clarification is essential.

[35] See Annexure to ENA submission, *Response to Consultation Papers, Proposed Energy Rule Changes*, 8 December 2011 (**ENA Response to Proposed Rule Changes**), Gilbert + Tobin, *Assessment of proposed changes to the regulatory decision making process under the National Electricity Rules: Report for the Energy Networks Association,* December 2011, p 12.
[36] Ibid.
[37] Ibid.

6. Rate of return framework

6.1 Industry proposed rate of return framework

The networks sector considers that there is positive benefit in amendments to the *National Electricity Rules* to align the cost of capital frameworks for electricity transmission and distribution. At this time, the successful operation of the flexible rate of return provisions of the *National Gas Rules* do not appear to warrant significant changes in the gas regime. Adoption of common frameworks across the three sectors would involve substantial amendment to the gas regime, and involve wider policy considerations which would be best pursued in a separate process able to fully examine the issues. One of the issues which would be important to consider is whether the particular features of gas pipeline and networks (such as their entrepreneurial characteristics arising from the status of gas a discretionary fuel) warranted a substantially different approach in relation to the detailed rate of return estimation process.

Industry supports the Commission's identification of significant flaws in the approach of fixing parameter values within the rules framework. This approach manifestly failed to promote forward looking cost of capital decisions taking into account the best available evidence during a time of significant disruption in capital markets from 2008-2009.

The Commission has established a sound set of initial principles for a effective cost of capital framework. To these principles, in view of the importance the sunk long-lived nature of capital investments networks are called upon to make, the principle of certainty should be added.

The network sector considers that an optimum balancing of this expanded set of design principles strongly favours the adoption of an approach based on that contained in Chapter 6, applying to electricity distribution. Experience to date with the electricity distribution regime also provides a basis for some targeted modification of that regime for its application across the electricity sector. The regime would be improve by a setting out of the overall objective and nature of the cost of capital estimate being sought, allowing estimates flowing from the application or departure from a Statement of Cost of Capital to be 'tested' against an overall WACC principle on a consistent basis. This would improve certainty around the operation of the 'departure criteria' for businesses, users and the regulator alike. The central purpose of the 'persuasive evidence' test, and its emphasis on promoting evidence led assessments of the empirical basis for any departures should continue to be a feature of the regime. Specific recognition of the inter-relationships between parameter values may also be a valuable incremental enhancement of the clarity of the regime.

The network sector concurs with evidence presented to the Commission from its experts that the existing rules frameworks have not in practice led to the full informational content and value of applying alternative cost of equity estimation or asset pricing models to be applied. This deficiency should be addressed by allowing such models to contribute to the testing of regulatory or network service provider proposed WACC values against the 'overall WACC' principles.

6.2 Answers to specific questions

Question 20: Are some WACC parameter values more stable than others, and sufficiently table to be fixed with a high degree of confidence for a number of years into the future? Would it be practical for periodic WACC reviews to cover only some parameters that are considered relatively stable in value, and require others to be determined at the time of each regulatory determination?

Question 21: Would it be useful if the AER periodically published guidelines on its proposed methodologies on certain WACC parameters as opposed undertaking periodic WACC reviews that locks in parameter values for future revenue/pricing determinations?

Fixed WACC parameters

There is no individual WACC parameter that does not rely on market-based evidence for reaching decisions on its appropriate value. The experience of the past 3-5 years demonstrates that it is unwise to presume that substantial changes in financial market conditions are unlikely to occur, and to establish a WACC framework that has limited capability for taking such changes into account. It follows that no WACC parameter value is sufficient stable for it to be "fixed with a high degree of confidence for a number of years into the future".

Consistent with this, the AEMC has itself identified a key criterion of a good WACC framework as one that is sufficiently flexible to deal with changing market conditions. The ENA supports the need for a framework that is capable of adapting to current market conditions, and does not believe that it practicable to define two classes of WACC parameter, according to expectations of their relative stability over time.

The observation that no parameter can be presumed to be sufficiently stable so as to be established on a 'set and forget' basis does not imply that there is no value in scheduling periodic reviews of the methodologies and parameter values that can be presumed to apply in subsequent regulatory determinations. There are good administrative efficiency reasons for maintaining such a process. In that context, the relevant question to be addressed is the circumstances in which it is appropriate to depart from the values or methods established in a periodic process, such as that envisaged under the Statement on the Cost of Capital (SoCC).

Criteria for a sound WACC framework

ENA is generally supportive of the attributes outlined by the AEMC of a good WACC framework. However, regulatory "certainty" should be added to these criteria, since this was an important motivation for the development of the current NER framework and continues to be an important objective.

The AEMC's 2006 review of TNSP revenue rules stated (p.iv) that one of its key objectives was:

> *…to improve the environment for investment by increasing regulatory clarity and certainty through the Rules.*

The Chapter 6/6A WACC frameworks enhance this objective through the requirement (p.83) that, when a parameter is not known for certain, the AER is required to:

> *…satisfy itself that current evidence on the value of the parameter is sufficient to justify a change from the value adopted in the last review.*

Periodic reviews

The SOCC has an important role in providing regulatory certainty, and improving the efficiency of WACC decisions. However, a key element of that process is the requirement for "persuasive evidence" (in the form of a minimum evidentiary threshold) before departing from previously adopted value.

The ability to undertake periodically published guidelines would be of little value if those guidelines were a substitute for the SOCC (ie, in the form of the old SORP) and involved no legal presumption that the methods, ratings or values be adopted unless there was persuasive evidence to depart from them.

There may be some value in periodic guidelines supplementing the SOCC and addressing circumstances where, between SOCCs, "persuasive evidence" does arise that a WACC parameter value or method is no longer appropriate.

ENA agrees that the AER should have the flexibility to publish a guideline setting out such issues, its proposed response and seeking stakeholder input. However, although not explicitly provided for, there is no apparent reason why the AER could not instigate such a process under the current Rules. Such arrangements are especially applicable if the change does not warrant bringing forward the SOCC, eg, the correction of the error on relation to gamma could have been dealt with in this manner.

Note that the intrinsic value in the SOCC is not just in the adopted WACC values, methods and credit rating, but also the SOCC:

- is a forum that considers the merits of different approaches to analysing particular WACC parameters, and so furthers the understanding of cost of capital issues in the context of Australian regulatory arrangements;
- provides guidance to NSPs on how to assess whether or not the prevailing WACC values are consistent current market conditions at the time of their determinations; and
- is an efficient process to seek input on cost of capital issues from all interested parties, including consumer groups, NSPs and other regulators.

One of the principles of a good WACC framework articulated in the AEMC's directions paper is the need for accountability for both the regulator and NSPs/gas pipelines in determining the WACC. This principle is currently lacking from the SOCC, since it is not subject to merits review. In our opinion, this is an anomaly of the current framework especially given the status of the SOCC values as the default to be adopted in the rate of return element of price/revenue determinations unless there is persuasive evidence for change. We understand that subjecting the SOCC to merits review cannot be achieved by a change in the rules. However, a recommendation by the AEMC that it be extended to the SOCC would be a constructive step in the formation of a good WACC framework.

Question 22: Given the uncertainty in estimating certain parameters, should the AER be required to produce the best possible values for all parameters or adopt a range from which it can choose a preferred estimate? Which WACC parameters are inter-related and should the rules recognise the inter-relationships of these WACC parameters?

The ENA does not support the introduction of ranges. The introduction of *a requirement to estimate a range* would seem to introduce an unnecessary step into the WACC estimation process for little or no apparent benefit.

The price/revenue determination process is required to reach a point estimate determination for the WACC. It is not obvious how or why a requirement to establish a range for one or more parameters can improve that process. Further, any suggestion that the AER should or could have unconstrained ability to choose parameter values from within the range (rather than adopting the best or most likely estimate) would confer unnecessary discretion to the AER, and introduce significant risks and uncertainty into the WACC determination process.

The SOCC should provide clear guidance to business so that they can confidently invest in long lived assets. Decisions to depart from the SOCC values should require evidence as to why a parameter is no longer appropriate (as measured against the WACC principle). The proper role of such a principle is to prevent the exercise of regulatory discretion from drawing different conclusions as to particular WACC parameters or values (something that it is often possible to do, from the same underlying evidence), unless the evidence supports a different decision being taken.

The introduction of a requirement to estimate a range cannot escape the need to select a point estimate for the WACC. In our opinion, there is a degree of inter-relationship between all WACC parameters. However, there are a number of critical inter-relationships including between:

- the MRP and the risk free rate;

- the MRP and the value of theta (the market value of distributed imputation credits);
- gearing and the equity beta;
- gearing and the DRP; and
- the cost of equity and the cost of debt.

The best method for recognising the inter-relationship of WACC parameters is to clarify in the rules that, when there is persuasive evidence for departing from a previously adopted value (either in the SOCC or at the time of a particular determination), the AER must have regard to the effect that this change has on other parameter values.

Question 23: How do the outcomes with the persuasive evidence test applying at the time of the regulatory determinations in Chapter 6 of the NER differ from the NGR rate of return framework? Does the persuasive evidence test make it less likely that values of WACC parameters will be updated as quickly as under the NGR framework, or vice versa?

An important element of the SOCC is its role in providing regulatory certainty, and improving the efficiency of WACC decisions. A key aspect of that process is the requirement for "persuasive evidence" (in the form of a minimum evidentiary threshold) before departing from previously adopted value.

We note that the persuasive evidence threshold has not prevented WACC parameters from being updated in light of new evidence. For example:

- in the 2009 WACC review the AER changed the following three parameter values:
  - the equity beta was reduced from 1.0 to 0.8;
  - the MRP was increased from 6.0% to 6.5%; and
  - the value of gamma was increased from 0.5 to 0.65;
- since the 2009 WACC review the value of gamma was reduced to 0.25 on appeal to the Tribunal; and
- the AER has subsequently returned the MRP to 6.0%.

The persuasive evidence requirement ensures that once a parameter value has been determined on the basis of a body of material (the original body of material), that value may only be departed from on the basis of material that, relative to the original body of material, is sufficient to justify that departure. That is, something new or additional is required relative to the previous body of material which compels the selection of a different parameter value. In the absence of something new, the parameter value may not change from the initially selected value. The setting of particular WACC parameter value invariably involves a level of judgement by the AER. The persuasive evidence requirement ensures that the WACC parameter value does not change unless there is "something" new or additional, for example a change in either the market evidence or a development in economic/financial theory.

One anomaly in relation to the current persuasive evidence test is that the threshold for changing a WACC parameter in the SOCC is different from (and less demanding than) that which needs to be established to depart from the SOCC at the time of the regulatory decision. This anomaly should be removed and the threshold for changing a WACC parameter in the SOCC should be raised so as to establish the threshold as that applying at the time of a determination.

It is difficult and perhaps not meaningful to assess the gas framework in isolation/comparative terms to electricity because, in practice, the two have influenced each other. For the two principal WACC elements (other than the DRP) in relation to which there has been the most significant controversy to date - being the MRP and gamma - decisions made by the AER have applied equally to both gas pipelines and DNSPs (but, given the constraints of Chapter 6A, could not be made for TNSPs), ie:

- o gamma - since the Energex, Ergon and ETSA Utilities appeal decision in May 2011, all gas and DNSP decisions have adopted a gamma of 0.25;
- o following the 2009 WACC review the AER adopted an MRP of 6.5% for all NSP and gas pipeline determinations, until the NT Gas decision (July 2011) and has since consistently then applied an MRP of 6.0%;

Question 24: How has the rate of return framework under the NGR worked alongside the NER frameworks?

Question 25: Are there any concerns about the lack of guidance in the NGR on how the AER and ERA will approach the rate of return decision? To what extent is the rate of return framework under the NGR influenced by the WACC approach adopted for the electricity sector by these regulators?

The rate of return framework for gas has been historically influenced by that applied to electricity. This has likely strengthened since 2008 and under AER regulation. Gas pipelines did make a number of submissions to the 2009 WACC review.

Following the WACC review the AER has consistently applied the following WACC parameter values and methodologies to gas pipeline determinations:

- the WACC/CAPM framework;
- gearing of 60 per cent debt / 40 per cent equity;
- an equity beta of 0.8;
- CGS yields of a 10 year term to maturity as the poxy for the risk free rate;
- Australian corporate debt of BBB+ credit rating and a term to maturity of 10 years; and
- until recently (NT Gas in 2011), an MRP of 6.5 per cent, but since that date a value of 6 per cent has been adopted in all DNSP and gas pipeline determinations.

On the experience to date it is difficult to point to clear distinctions in terms of the substance of AER decisions on WACC that have differed as between the DNSP and NGR frameworks. This is not unexpected, since they have been operated by the same entity and, although it has had the opportunity to do so, the AER has not elected to use the greater flexibility available to it under the NGR framework. By way of example:

- Jemena submitted evidence on the cost of equity using a Fama-French model in the context of the NSW gas distribution review, but the AER rejected any consideration of this model on the basis it was not 'well accepted'; and
- The AER has been critical of what it says is inflexibility in the specification of the DRP benchmark in the NERs, yet it has adopted exactly the same benchmark in decisions made under the NGR, even though it would have been free to explore other options.

Question 26: Are there reasons to adopt a WACC definition other than the vanilla post-tax nominal definition that is used under the NER? Alternative proposals should explain why that alternative is likely to result in a better WACC estimate.

There is no reason to change the current definition of the rate of return as a vanilla post-tax nominal WACC.

Question 27: Should the AER/ERA be given discretion to consider models other than the CAPM when estimating the required return on equity under the NGR? What prescription or principles could the rules contain to guide the way in which information from other models might be used to produce a better WACC estimate?

There should be more flexibility to adopt alternative models as a cross-check on the reasonableness of cost of equity estimates derived under the CAPM.

The ENA supports the view that consideration of additional information provided by alternative cost of equity models has potential benefits. In particular, there is sound logic in the opinion of Professor Stephen Gray when he states that:

…it is difficult to make the case that allowing the regulator to consider more information about the required return on equity would systematically result in lower-quality estimates. [page 28, SFG report]

As a general principle, where the primary method produces counter-intuitive results, this should prompt further inquiry and cross-checking using alternative models. It is apparent from recent decisions that the AER does not see scope to do this under the current rules.

Question 28: Are there any reasons why an appropriate WACC estimate cannot be provided to NSPs and gas service providers from a common WACC framework, without necessarily requiring the same parameter values to be adopted across the electricity transmission, electricity distribution and gas sectors?

There are a number of WACC parameters that are common to all industries, such as:

- the risk free rate;
- the market risk premium; and
- gamma.[38]

For all other WACC parameters, there is no reason why a common WACC framework applied across electricity and gas businesses could not accurately assess the differences in characteristics between these types of businesses to establish appropriate WACC parameter values or credit ratings.

Question 29: Which rate of return framework would best meet the key attributes identified? Are there any other attributes that should be considered?

The chapter 6 framework is best equipped to adapt to changing market conditions and new evidence, while providing stability and certainty for stakeholders. Specifically, chapter 6 framework contains an established process (the SOCC) for analysing and settling on WACC parameters values, methodologies

[38] Noting that a market wide payout ratio has been adopted in recent regulatory decisions.

and credit values. We note that the 2009 WACC review has the effect of settling a number of the WACC parameters values, ie:

- gearing of 60 per cent debt / 40 per cent equity;
- an equity beta of 0.8;
- CGS yields of a 10 year term to maturity as the poxy for the risk free rate; and
- a debt risk premium benchmark of Australian corporate debt of BBB+ credit rating and a term to maturity of 10 years.

The chapter 6 framework has also allowed WACC parameters to change in light of current market or developments in theory or technique, i.e.:

- the analysis underpinning the gamma value of 0.65 was contested before the Australian Competition Tribunal and adjusted to 0.25 (which has then been applied in all subsequent DNSP and gas pipeline decisions); and
- the MRP of 6.5 per cent has been returned by the AER to a value of 6 per cent, reflecting its view that Australian equity markets have return to pre-GFC conditions

However, the Chapter 6 framework could be enhanced to address the concerns raised by the AEMC, specifically:

- to remove any doubt as to the ability for the process to take into account the interaction between individual WACC parameters, suitable Rule amendments might be contemplated to clarify that the AER must consider the effect of departing from a previously adopted value on other WACC parameters. However, the ENA's view is that the current rules impose no meaningful limitations on the consideration of inter-relationships between WACC parameters and that any shortcomings arising from the experience to date are the results of the way the framework has been applied, rather than the way it could be applied; and
- to clarify that the AER should have regard to all available evidence to ensure that WACC meets the WACC principle.

6.3 Estimating the cost of debt

Estimation of the cost of debt has emerged as one of the most contentious elements of the regulatory process over the past five years, due to a range of market developments and regulatory practices seeking to adapt to changing data availability and circumstances.

The network sector supports the key elements of a benchmark approach to cost of debt estimation. In this respect, the currently specified debt risk premium specified in the *National Electricity Rules* remains appropriate, and reflects the characteristics of current financing practices and policies of network service providers. Propositions that the current benchmark systematically overstate prevailing conditions in the market and create a 'windfall' gain to regulated entities are not consistent with a full assessment of the financing opportunities and risks of these entities. Alternative approaches which have been developed by several jurisdictional regulators such as IPART and ERA have material practical and theoretical weaknesses, most critically in failing to result in clear replicable decision-making against a benchmark that matched businesses' observed funding activities.

The proposal to make greater use of historical trailing index approaches in setting the cost of debt made by EURCC is, by contrast, a positive initial step towards a potentially workable approach. ENA members support the development of a historical trailing average benchmark. This is a task of significant complexity, and best pursued outside of the relatively restrictive constraints of this rule change request. A range of methodological, implementation and measurement issues would need to be the subject of detailed consideration prior to industry having confidence that the approach would better meet the National Electricity Objective than the current rule provisions.

The network sector notes there have been a number of significant developments since the industry provided its comments in relation to the appropriateness of the drafting of the existing debt risk premium clause in Chapter 6 and 6A. In particular, a range of modified methodologies taking into account wider sets of possible evidence have been proposed by the AER, and recent Competition Tribunal appeal judgments have provided further clarity on the approaches likely to be consistent with the relevant clauses. This, together with the Tribunal's positive calls for the AER to further develop its practical approach to applying the provisions in consultation with stakeholders, means that the network sector considers the existing drafting of the debt risk premium clauses to be workable.

6.4 Answers to specific questions

Question 30: Is the benchmark DRP approach likely to overstate the prevailing cost of debt, having regard to the suggestion that the overstatement may be a reflection of shorter maturity debt leading to a higher refinancing risk for NSPs? What weight should be placed on the views of market analysts on the ability of stock market listed NSPs to out-perform their cost of debt allowances?

The current DRP benchmark has the following three characteristics:

1. Australian benchmark corporate bond rate

2. a term to maturity of 10 years; and

3. a BBB+ credit rating.

Australian corporate bond rate is an appropriate benchmark since all NSPs are geographically located in Australia and are Australian corporate identities. There is no evidence that the other elements of the debt benchmark do not reflect the current financing practices of NSPs. This is for the following reasons:

- o 10 years is an appropriate benchmark since it is likely to strike the best balance between refinancing risk for long lived assets and the capital market limitations on very long dated debt. There is no evidence that firms do not on average issue long term debt.
- o in the 2009 SORI process, confidential submissions by the NSPs presented data on the weighted average term to maturity of debt issued as at the end of financial year 2007, for a group of privately owned energy network businesses as 10.14 years.[39]
- o it should be expected that business will not only issue debt of precisely 10 year duration. Rather, in practice debt issued by any particular NSP will depend on the prevailing conditions in the market (ie, the various yields on debt with different terms to maturity), its own current portfolio of debt, and its assessments of refinancing risks;
- o issuing shorter maturity debt is a rational response to temporary high yields (ie, such as arose during the high of the GFC), since the 'flight from risk' that characterise periods of systemic financial distress implies greater reluctance on the part of both investors and firms to make long term financial commitments. However, firms that issue shorter term debt accept higher levels of refinancing risk, while investors committing their funds for shorter terms generally suffer a yield penalty; and
- o in other words, the shortening of debt terms involves in a shift of risk from the debt to the equity elements of capital. It would not be appropriate to reduce the term of debt without a corresponding increase in the cost of equity.

No evidence has been presented by the AER that a credit rating of BBB+ is no longer appropriate. The AER's own assessment of data available during the 2009 SORI led it to conclude that BBB+ credit rating is consistent with the revenue and pricing principles (see p 391 of the Final Decision)

The AER suggested in its Rule change proposal that factors other than term and credit rating should be included in the benchmark, such as:

- o bond size;
- o liquidity;
- o credit wrap features;
- o comparable bond issuances;
- o market sentiment;
- o scarcity and desirability of issuer;
- o industry prospects;
- o financial status of issuer; and
- o abnormal features.

In the ENA's view, all but one of these features are inappropriate aspects to be included in a benchmark, ie:

[39] The sample of private NSPs included, Envestra, CitiPower and Powercor, ETSA Utilities and SP AusNet.

- company specific features of particular bond issue (bond size, liquidity, scarcity and desirability of issuer, financial status of issuer and abnormal features) to be incorporated into a benchmark. When observed, such features may warrant different weight being placed on a particular bond in order to derive a reasonable estimate of the benchmark – however, there is no case for the benchmark itself to be adjusted to take account of such variables; and

- the remaining features (but for one) reflect issues arising in the measurement of a bond yield, ie, comparable bond issuances, market sentiment and credit wrap features

Each of these issues involve a complication of one form or another in the estimation or measurement of the benchmark, and assume particular importance where the available sample of bonds is small. However, the appropriate place to take account of such matters is in the benchmark estimation process, not in the specification of the benchmark itself.

The only feature identified by the AER for which there may be an 'in principle' case for refining the benchmark is whether or not to specify an industry-specific benchmark, ie, the regulated energy utility sector. However, when the ERA considered the set of industry specific bonds, it resulted in very small sample set and so for that reason was rejected by the Authority

Question 31: What are the pros and cons of the recent approaches taken by IPART and the ERA in estimating the DRP?

WA Economic Regulation Authority approach

The approach for setting the DRP adopted by the Economic Regulatory Authority of Western Australia (the ERA) in its recent draft determination for Western Power involves:[40]

- the specification of a credit rating equal to the median rating of Australian energy companies (using data published by the AER in the 2009 SORI) and the A+ rated Synergy, which results in a benchmark value of A-;

- the view that the term to maturity for the DRP and risk free rate should match the length of the regulatory period since "[a] term of the risk free rate which matches the length of the regulatory period of 5 years better reflects the financing strategies of regulated businesses in Australia"41

- estimating the above benchmark by giving equal weight to the following two samples of bonds:

  - a term weighted average yield of a sample of bonds (fixed, floating, bullet and callable/putable) with a A- credit rating and at least 2 years to maturity; and

  - a term weighted average yield of a sample of bonds (fixed, floating, bullet and callable/putable) with a A- credit rating and at least 5 years to maturity.

Table 1, below, sets out respective weights given to the bonds sampled by the ERA in its draft decision for Western Power.

[40] Economic Regulatory Authority, *Draft Decision on Proposed Revisions to the Access Arrangements for Western Power Network,* 29 March 2012.
[41] *Western Power, Draft Decision page 158*

- **Table 1 - Sample weight of Sampled Bonds applied by the ERA**

Issuer	Term to maturity	Observed DRP	Overall weight
Aust & NZ Banking group*	10.31	1.676	0.119
Powercor Australia LLC*	9.88	1.660	0.114
Coca-Cola Amatil Ltd*	9.58	1.369	0.110
Stockland Trust Manageme*	8.74	3.186	0.101
National Australia Bank*	5.81	2.170	0.067
Aust & NZ Banking group*	5.63	1.991	0.065
SPI Electricity & Gas*	5.57	2.327	0.064
Commonwealth Bank Aust	5.24	1.867	0.060
Aust & NZ Banking group*	5.01	2.035	0.058
SPI Australia Assets Pty	4.98	2.543	0.020
Coca-Cola Amatil Ltd	4.92	1.518	0.019
Commonwealth Prop Fund	4.78	1.042	0.019
Australia Pacific Airpor	4.49	2.550	0.018
ETSA Utilities Finance	4.58	2.152	0.018
Stockland Trust Management	4.34	2.880	0.017
Australia Pacific Airpor	3.79	2.762	0.015
Transurban Finance Cmpny	2.07	2.327	0.015
SPI Australia Assets Pty	3.45	2.114	0.014
Stockland Trust Management	2.97	2.581	0.012
Mercedes-Benz Australia	2.78	1.422	0.011
Volkswagen Fin Serv Aust	2.73	1.889	0.011
Volkswagen Fin Serv Aust	2.91	2.157	0.011
Australia Pacific Airpor	2.49	2.378	0.010
Coca-Cola Amatil Ltd	2.25	0.862	0.009
Mercedes-Benz Australia	2.11	1.559	0.008
Transurban Finance Co Pt	3.69	1.732	0.008
Volkswagen Fin Serv Aust	2.09	1.853	0.008

- *Source: NERA calculation*

Note that the current Rules do not prevent the AER adopting a method that draws upon elements of the ERA approach since:

- the AER is capable of changing its debt benchmark (ie, term of the risk free rate or credit rating), either through an updated SOCC or at the time of a determination if there is persuasive evidence for change; or

- the AER could adopt the ERA's sampling/yield aggregation approach to estimating a benchmark DRP (having changed the benchmark).

Nevertheless, the ERA's approach contains a number of material errors, including:

- o the adoption of a 5 year term to maturity does not in fact reflect the financing strategies of regulated businesses, which demonstrably do finance debt at issuance with terms to maturity on average greater than 10 years (as the AER itself concluded in its 2009 SORI);
- o the inclusion of Synergies (a government owned energy retailer, with a credit rating of A+) is an inappropriate comparator to a stand alone NSP;
- o there are significant methodology issues with the approach adopted by the ERA to measure its benchmark, ie:
  - the sample involves bonds with terms to maturity that range from 2.09 years to 10.31 years and have a weighted average life of 6.9 years, rather than the benchmark of 5 years;
  - there is little theoretical basis for the effective weights that the ERA places on individual bonds, which place greatest weight on with the longest life rather than those that are closest to the benchmark; and
  - the ERA has not addressed in detail the relevance of its sample of bonds for predicting the cost of debt for a stand alone energy utility, including the concerns expressed by the AER's own consultant (Oakvale Capital) of using bonds issues by the SPI entities (given perceived support by the Singapore Government) nor the appropriateness of including bond issues from the major trading banks; andby not having regard to the Bloomberg FVC ignores a respected market estimate of the benchmark and is also inconsistent with recent Tribunal decisions.

IPART approach

The approach adopted by IPART in its recent determination for the Sydney desalination plant involves:

- o the adoption of a credit rating of BBB/BBB+, and a term to maturity of 5 years;
- o the measurement of that benchmark using a sample of:
  - o the 5-year Bloomberg fair value curve (FVC);
  - o Australian issued bonds (with a term to maturity of at least 2 years)
  - o Australian corporate but US-issued bonds (with a term to maturity of at least 2 years)
- o IPART then selects the median value within the sample and adds 20 basis points for debt raising costs.

It again should be noted that the current Rules do not prevent the AER from adopting IPART's approach. Nevertheless, IPART's approach also contains a number of material errors, including:

- o the adoption of a 5 year term to maturity does not in fact reflect the financing strategies of regulated businesses, which demonstrably do finance debt at issuance with terms to maturity on average greater than 10 years (as the AER itself concluded in its 2009 SORI);
- o IPART provides little or no analysis on the construction of its sample of like bonds, stating only that:[42]

[42] IPART, *Developing the Approach to Estimating the Debt Margin, Other Industries – Final Decision*, April 2011, page 34.

> "the criteria of selecting bonds with at least 2 years remaining to maturity balances the need to include only relevant observations with the requirement of having a sufficient number of observations"

- o IPART provides no analysis as to why the median bond yield (ie, Leaseplan Australia) best represents the likely benchmark yield for a bond with a credit rating of BBB and a term to maturity of 5 year;

The AEMC has identified as a key criteria for a good WACC framework as one that creates accountability for both the regulator and the NSP/gas pipeline. IPART's approach to estimating the benchmark does not satisfy this criterion because it does not articulate the reasons for critical elements of its DRP decision, particularly where it has exercised discretion on matters that have a significant effect on the outcome.

Conclusion

We note that the current NERs do not prevent the AER from adopting either of the approaches adopted by the ERA or IPART. Further, if either of these approaches amount to a reasonable approach to estimating the DRP (which the ENA believes they do not), their application by the AER could be expected to be upheld on appeal to the Competition Tribunal. However, for the reasons set out above the ENA believes that both the approaches adopted by IPART and the ERA are deeply flawed and so would likely be overturned by the Tribunal.

The network sector encourages the AER to heed the advice of the Tribunal that:

> "If the AER were to decide that the EBV [Extrapolated Bloomberg Value] was an unreliable indicator for the purposes of deciding that DRP, it would be desirable in the longer term to develop an alternative coherent and consistent methodology, in consultation with the relevant regulated entities and other interested parties. Although the DRP must be determined at a particular point in time, the use of a consistent and acceptable methodology would ensure regulatory consistency, and in relation to particular matters would also facilitate efficient decision making and in turn reduce the number of reviews of the DRP decisions by the AER brought to the Tribunal. While such a task would be a complex and lengthy one, it is one the Tribunal commends to the AER." [*Envestra appeal – 2012*]

Question 32: What evidence is there that the DRP benchmark in the NER may have changed? Would it be appropriate for the regulator to specify the DRP benchmark in any periodic reviews or would it be more appropriate to specify it at the time of the determinations?

The Chapter 6 WACC framework allows the AER to adopt a different DRP benchmark (in terms of the credit rating or term to maturity of the risk free rate) if there is evidence that the 2009 SORI values are no longer applicable. To date, the AER has not sought to depart from its 2009 SORI decision on the basis that the benchmark is no longer appropriate.

The ENA recognises that, for a period following the onset of the GFC, corporate bond issues did tend to take place at shorter maturities (or, for a period, not at all). However, the ENA rejects the suggestion that this phenomenon implies that the benchmark maturity should change. Equally, in alternative circumstances where it was observed that bond maturities had extended beyond ten years, it would similarly be unwise to amend the benchmark.

The existence of a relatively stable benchmark has strong merit from the perspective of allowing NSP's to plan and manage their financing and interest rate risk management needs in a stable, predictable regulatory environment. There is no case for the benchmark to chase short or medium term trends in financial market conditions. Rather, it is far preferable to establish a benchmark that is consistent with the long term evidence of debt financing practices, while recognising that short term trends are likely to imply observed variations around it.

The SOCC continues to have an important role in providing regulatory certainty, and improving the efficiency of WACC decisions. In addition to specifying the benchmark credit rating and term the SOCC also provides guidance as to the analysis necessary to justify a departure from the SOCC values.

Question 33: Is the EURCC's proposal of establishing the cost of debt using historical trailing average compatible with the overall framework for estimating a forward-looking rate of return? What are the potential benefits of using a trailing average and do they outweigh the potential costs if the estimate is less reflective of the prevailing cost of debt for NSPs?

A significant number of ENA members support giving further consideration to using an historical average when setting the benchmark debt allowance, with the average applying either to the total benchmark cost of debt or to the debt risk premium element.

The particular proposal put forward by the EURCC is one form of a trailing average that could be implemented. The key elements of the EURCC proposal are:

- the continued use of the cost of debt being set by reference to a benchmark;
- the trailing average of the total cost of debt over a period equal to the term to maturity of the debt benchmark; and
- annual updating of the cost of debt allowance during the regulatory control period.

An alternative to the EURCC form of a trailing average is outlined in the Joint Report on the DRP.[43] The principle difference with the method proposed by the EURCC is that it calculates a trailing average of the benchmark DRP while the risk free rate would continue to be fixed at the start of each regulatory control period. This alternative approach would reflect the current financing strategies of most privately owned NSPs.

The ENA supports exploring the possible adoption of an historical trailing average approach covering both of the alternatives described above. Such an approach, subject to implementation issues, could:

- result in an allowance that better approximates the debt costs incurred by an efficiently financed, benchmark firm;
- avoid exposing NSPs to the unnecessary risk that the actual debt cost for a benchmark efficient firm is significantly different to the regulatory allowance during a regulatory control period, by updating the cost of debt throughout the regulatory period; and
- depending on the form of the trailing average could more closely reflect the actual financing/risk management practices of a number of NSP, thereby reducing financing risks for those businesses.

The merits of each form of the trailing average would need to be closely examined as well as the potential transitional issues that each form of trailing average will impose on some businesses depending on their current financing approaches. The ENA believes that transitional provisions will be necessary regardless of the form of trailing average, and that an essential proposition is that network businesses should not be unduly penalised for mitigating their current debt financing risks.

[43] Joint report, *Trailing Average Approaches to the Cost of Debt Allowance*, 16 April 2012, (**Attachment E**).

However, the development of such an approach would represent a significant modification to the current principle used to set the cost of debt allowance, since it:

- cannot be undone, because switching between a spot and trailing average exposes NSPs and customers to “opportunism”, and in any case the benefits of a different approach only arise if it were to remain in place over the longer term; and
- introduces considerable implementation issues, such as:
  - how to construct an average of historical estimate that spans the period of the GFC, which the experience to date shows is a significant challenge (albeit is a period for which Tribunal decisions will provide valuable guidance); and
  - developing a trailing average benchmark that works for all firms regardless of their stage in the investment cycle, ie, that can be applied to NSPs with a future investment program that is either very significant or relatively modest;
- requires significant restructuring to the Rules to be implemented, including to ensure that merits review arrangements are preserved.

ENA members are deeply sceptical that such an approach can be designed and implemented in a wise, considered way within the timeframe of this rule change process. Its strong preference is to carve out this issue into a separate review process, so that the many implementation and other complexities can be thoroughly examined.

Question 34: What possible changes would be required in the NER to implement the EURCC's trailing average approach?

The ENA envisages that substantial changes would be needed to the NER to accommodate the adoption of a trailing average approach to the DRP. These are likely to include:

- the separation within the Rules of the risk free rate used to estimate the cost of debt from that used to estimate the cost of equity ;
- the development of a revised overarching principle for application to the debt element of the WACC (alone), potentially adopting the concept that the cost of debt should reflect the “average historical financing costs of a benchmark efficient NSP”;
- the creation of an annual pass-through mechanism to allow the trailing DRP to be annually updated, through the adoption of a specified updating methodology; and
- the need to establish empirical estimates of the DRP over the period of the trailing average (ten years), which coincides with the period of the GFC and its disruptive effects on both the quality and quantity of bond yield data.

Such a change would also involve a substantial adjustment to the debt risk profile for some NSPs and so the nature and extent of the interest rate and refinancing risk management decisions for NSPs.

The process of ensuring that all the above issues are dealt with in a thorough manner with adequate consideration to the risks and possible unintended consequences is likely to be extremely challenging – if not wholly unrealistic – within the current rule change timetable.

For these reasons, the ENA is strongly of the view that this issue should be considered by means of a separate review process, so that the many implementation and other complexities can be thoroughly examined.

7. Regulatory process

This section of the ENA's submission addresses Chapter 7 of the Commission's Directions Paper on regulatory determination process issues.

As a general matter, the ENA notes that the policy intention of the drafters of Chapter 6A (and Chapter 6) was to set out in the Rules the process that would be followed by the AER in making distribution and transmission determinations. This was so there would be transparency and certainty as to the administrative processes to be followed. The ENA submits that this policy intention remains appropriate and that the Rules should set out the key administrative steps to be followed in each determination process.

However, equally important to the specific process to be followed is the manner of its implementation. How each step is to be implemented and the expectations of the AER, the relevant service provider, and other stakeholders, should properly be the subject of dialogue between these parties. The Rules should set out the basic process, but should not seek to deal in detail with the implementation of the process including because each regulatory determination process will be different and processes should be permitted to also evolve over time reflecting knowledge gained from each determination. In this vein, the ENA has proposed a number of non-Rule based initiatives that it considers would assist in addressing some of the concerns raised by the AER in its proposed Rule change.

In relation to the next steps on the regulatory process issues, the ENA considers that once the AEMC has determined the policy direction for rule changes on regulatory processes and procedures, that there would be merit in establishing an AER and stakeholder working group to comment on the detail of the AEMC's preferred rules. This may assist the AEMC to confirm its rules are workable in practice.

The ENA envisages that with a clear policy direction, the AER, NSPs and stakeholders could reach consensus on the majority of points of detail. It is likely that there will also be differences of view on some points, however a working group (rather than the normal process involving submissions) is a better process to clarify the basis of any differences. The ENA accepts that the AEMC would determine, in its own discretion, the rules it ultimately puts forward in its draft decision.

The ENA considers that such a working group process is consistent with the positive interaction between the AER, the NSPs and the other stakeholders which the AEMC points out is important in contributing to the success of the regulatory determination process.[44]

7.1 NSP submissions received during a regulatory process

Any rule change proposal must seek to balance the tensions existing between the need for NSPs and other stakeholders to have reasonable opportunity to scrutinise and comment on information produced by the AER and by others and the time constraints faced by the AER. As noted above, the Rules should provide the framework for the necessary steps in the process towards the publication of the final determination. However, beyond the Rules, open consultation between the AER, NSPs and other stakeholders should be encouraged so that these parties jointly work towards robust regulatory decisions, driven by, wherever feasible, full disclosure of information relevant to the decision making process (by all stakeholders, including the AER), as well as sufficient time to assess and test that information. This should be the starting point for any Rule change proposal.

[44] AEMC *Directions Paper* (2012), p.123.

7.1.1 The current National Electricity Rules

The NER prescribes time frames for NSP initial and revised proposals, submissions received by stakeholders during a regulatory process and draft and final determinations made by the AER. The NSP submits a regulatory proposal to the AER 13 months before the expiry of a regulatory determination.[45] Stakeholders can make submissions on a NSP's regulatory proposal to be provided within 30 business days after publication of the regulatory proposal.[46]

Following this, the draft regulatory determination is published by the AER. Although not explicit for distribution, for transmission the draft regulatory determination must be published as soon as practicable but not later than six months after a TNSP submits its regulatory proposal.[47]

NSPs then submit a revised regulatory proposal not more than 30 business days after the draft regulatory determination has been published. The revised regulatory proposal may only incorporate the substance of any changes required to address matters raised by the draft regulatory determination or the AER's reasons for it.[48]

Stakeholders in distribution determination processes can make submissions on the AER's draft regulatory determination to be provided 30 business days after its publication of the draft regulatory determination, and stakeholders in transmission determination processes have at least 45 business days after the predetermination conference (which usually occurs a few weeks after the draft regulatory determination).[49]

Stakeholders may also make submissions on the revised proposal on invitation by the AER to do so. The NER expressly provides that the NSP has a right to submit a revised regulatory proposal '[in] addition to making written submissions'.[50]

In making the final determination, the AER must consider any submissions made on the draft regulatory determination or on any revised regulatory proposal. [51] The final regulatory determination must be published as soon as practicable but not later than two months before the commencement of the new regulatory control period. [52] The AER has the discretion to consider late submissions.[53]

7.1.2 AEMC's initial position

The AEMC identified the following issues in the current regulatory determination process:[54]

- NSPs were submitting to the AER a greater quantity of material after the draft regulatory determination, both directly in response, and through subsequent submissions. The AEMC's initial view was that the quantity of the material being submitted suggested that what was being submitted by NSPs went beyond information pertaining to unforseen or changed circumstances.

- Late submissions provided by NSPs are impeding the ability of the AER and other stakeholders to assess and scrutinise the information.

[45] Clauses 6.8.2(b) and 6A.10.1(a)(1).
[46] Clauses 6.9.3(c) and 6A.11.3(c).
[47] Clauses 6.10.2 and 6A.12.2(a).
[48] Clauses 6.10.3(a) and 6A.12.3(a).
[49] Clauses 6.10.2(c) and 6A.12.2(c).
[50] Clauses 6.10.3(a) and 6A.12.3.
[51] Clauses 6.11.1 and 6A.13.1(a).
[52] Clauses 6.11.2 and 6A.13.3.
[53] Clauses 6.14(a) and 6A.16(a).
[54] AEMC *Directions Paper* (2012), p.128-129.

- However, the period of time for the NSPs to respond to the AER's draft regulatory determination often falls over the Christmas / New Year period, and therefore can constrain access to adequate resources, and be a source for late submissions.

- Restricting the scope of NSP submissions may be difficult to implement if it results in inconsistencies between the NEL and the NER.[55]

- Greater engagement between the AER and the NSP on a formal or informal basis in the lead up to the draft regulatory determination about the likely issues that the AER will raise may alleviate the issues referred to above.

The AEMC identified five options, which it did not consider to be necessarily mutually exclusive, to address the issues raised by the AER and other stakeholders:[56]

Option 1: Creating new consultation steps in the regulatory determination process, via: [57]

- the requirement of a mandatory issues paper stage; and / or

- the inclusion of submissions / cross submissions stage.

Option 2: NSP proposal to extend the period for NSPs to submit revised regulatory proposals by:

- extending the 30 business day period for an additional two weeks when it falls over the Christmas and New Year period.

Option 3: Commencing the regulatory determination process earlier (i.e. three months earlier).

Option 4: Delaying the publication of the final regulatory determination until a specified number of days after the last material submission is received.

Option 5: Restrict the scope of NSP submissions (AER's proposal).

The AEMC noted that Options 1 and 2 would have the effect of shortening the time within which the AER must make its final regulatory determination by four weeks and that that time frame may not be adequate. Option 3 would ameliorate this effect.

The AEMC observed that while Options 1 to 3 may improve the amount of consultation and reduce the volume of material being considered prior to the final regulatory determination, none of these options discouraged late submissions or the extent of the revised regulated regulatory proposals.

The AEMC did not elaborate on the appropriateness or otherwise of Option 5.

7.2 Answers to specific questions

Question 35: What factors or principles would promote an effective regulatory determination process?

The central aim of the regulatory process is to produce robust regulatory decisions. Principles which underpin this objective include:

[55] Stakeholder submissions indicated a discrepancy between sections 16 and 28ZC of the NEL and the NER, and the proposal to limit NSP information that the AER can take into account.
[56] Ibid.
[57] Currently, under the NER the publication of an issues paper is an optional stage, following the regulatory proposal – clauses 6.9.3(b) and 6A.11.3(b).

- Full disclosure of material information by NSPs and AER, particularly in relation to matters that are material to the decision that will be made.

- Appropriate time in which to consider and respond to all matters, particularly in relation to matters that are material to the decision that will be made.

- Meaningful participation by relevant stakeholders in the regulatory determination process.

- Accountability and transparency.

The ENA agrees with some of the initial views expressed by the AEMC that the current Rules may not adequately balance the tensions existing between the need for NSPs and other stakeholders to have reasonable opportunity to scrutinise and comment on information produced by the AER and submitted by others and the pressure placed upon the AER in having to assess all relevant information and produce a final determination within fixed time constraints. This is also commented upon in the expert report of Geoff Swier provided with this submission.[58]

However, it remains a paramount objective that NSPs should have sufficient time to prepare their revised regulatory proposals and should submit as much relevant information as possible in their revised regulatory proposal. Such objectives are self evident and a necessary component of informed and robust decision making.

The ENA considers that the determination process should allow the AER to consider supplementary information that is provided by a NSP (or other stakeholder) following the close of submissions on the draft decision where, for good reason, that information was not able to be provided by the close of submissions on the draft decision. The determination process as implemented by the AER currently permits this and this flexibility should be retained. In considering this issue, the following matters should be noted:

- In a number of regulatory processes information has been submitted after the date that submissions on the draft decision closed in response to a request for submissions from the AER where the AER is considering a material departure in the final decision from a position expressed in its draft decision. The Rules must provide flexibility for NSP's to provide submissions in response to such changes, and this is also a requirement of section 16(1) of the National Electricity Law.

- It should be expected that any material submitted after the date submissions on the draft decision close would be of a very limited nature. The overwhelming majority of the information required by the AER to assess a regulatory proposal and make its determination is generally provided by way of a combination of:

  - the service provider's response to a regulatory information notice served on the service provider by the AER (if any), in which case the service provider is compelled to provide the information specified in the notice by the time specified in the notice; and

  - the information in the service provider's regulatory proposal, revised regulatory proposal (if any) and the service provider's response to the draft decision.

The ENA agrees that in circumstances where a restriction is imposed on the content of the revised regulatory proposal, the NER should not permit this restriction to be circumvented through the use of submissions, *on the proviso* that this policy does not amount to a prohibition on the AER having regard to information that is provided to it outside of the explicit process steps in the Rules. The Rules must be flexible enough to adapt to the individual circumstances of each regulatory determination process and allow for consideration of information that is material to the determination to be made by the AER and

[58] Attachment F, p 39-44.

that, for a legitimate reason, could not be submitted within the bounds of the explicit process steps defined by the Rules.

As noted in the expert report by Geoff Swier provided with this submission, rule change proposals which confine the content of regulatory proposals and submissions to certain categories of information in pursuit of increasing the incentive for NSPs to provide complete initial and revised proposals are misguided.[59] This incentive already exists, including through the decision-making rules that apply, for example, to capital and operating expenditure forecasts and also through other features such as the risk of not being given leave to make an application for merits review if the service provider has acted in a manner to delay the determination process. Furthermore, an absolute prohibition on the AER having regard to material submitted outside of the explicit steps in the Rules could lead to relevant information not being taken into account even where the AER considered it to be relevant.[60] Such a prohibition would not be consistent with the NEL, specifically section 16(1).

As stated, the ENA's overarching objective is to ensure that the regulatory determination process encourages open dialogue between the AER, NSPs and other stakeholders so that in the application of the Rules, the AER and regulatory participants work towards robust regulatory decisions, driven by full information and appropriate time frames for the proper assessment and analysis of that information.

Question 36: What option(s) would be the best way of addressing problems with the regulatory determination process?

The ENA submits that many of the concerns that arise from the current determination process could be addressed by commencing the regulatory determination process earlier. Bringing forward the commencement of the regulatory process by about two to three months would facilitate the following:

- NSPs to submit any revised regulatory proposal together with their submission on the AER's draft decision, which would place stakeholders in a position where they are responding to any revised proposal and service provider response to the AER's draft decision at the same time, as opposed to the current position where all parties (service providers and other stakeholders) respond to the AER's draft decision at the same time. The ENA would propose that the service provider be required to submit any revised proposal and response to the AER's draft decision no less than about 45 business days from the AER's draft decision (i.e. extend the timeframe from 30 days to approximately 45 business days for the making of the revised regulatory proposal as well as the submission on the draft determination).

- The making of submissions by stakeholders on: the AER's draft decision; the service provider's revised proposal (if any); and the service provider's submission on the draft decision, within about 20 business days after the service provider's jointly submitted revised proposal and submission on the AER's draft decision, which is currently the timeframe typically provided for the close of submissions on the AER's draft decision.

- The making of cross-submissions following the submissions made on the AER's draft decision and on the NSP's jointly submitted revised regulatory proposal and submission on the draft decision. This step explicitly provides for the service provider to respond to stakeholder submissions, as well as for stakeholders to respond to each other's submissions. A period of about 15 business days is proposed for this step.

- Additional time for service providers to determine pricing for services following the AER's final determination. This is particularly relevant for DNSPs who are required to submit pricing proposals to the AER within 15 business days of the AER's final determination. The current timeframes for the submission of the pricing proposals and for the AER to assess those proposals is very short.

[59] Attachment F, p.33-34, 37-38
[60] Ibid

> To deal with this issue it is proposed to bring forward the regulatory process by about one month, so that the AER would be required to make the final determination three months prior to commencement of the regulatory period.

The above proposal would add about six weeks to the determination process, and would bring forward the regulatory process by around two to three months.

The ENA considers that by bringing forward the commencement date of the regulatory process by around two to three months this would enable the additional consultative steps to be incorporated as well as provide more flexibility in the time allocated to finalise pricing proposals after the publication of the final determination. In relation to the dates for the submission of the service provider's joint revised proposal (if any) and submission on the AER's draft decision, and the date for stakeholder submissions on the draft decision and cross-submissions, these dates would be specified in the AER's draft decision. These proposals are considered in further detail below.

(a) Joint revised proposal and submission on the draft determination

As noted above, the ENA proposes that the time for a NSP to prepare a revised regulatory proposal be extended by approximately three weeks so that the NSP can also submit its submission on the draft determination at the same time. Extending the time for NSPs to submit its revised proposal and submission, will place stakeholders in a better position to address *both* the revised proposal, as well as the NSP's submission on the draft determination. The ENA considers that this will enhance the objective of providing stakeholders with an opportunity to scrutinise relevant information.[61]

Commencing the regulatory process earlier by two to three months as suggested will avoid issues relating to resource constraints which impact revised regulatory proposals given that the timing between the publication of the draft determination and the lodging of the revised regulatory process usually falls between the Christmas and New Year period (for NSPs whose regulatory period commences 1 July).

(b) Cross submissions stage

The ENA supports the inclusion of a cross submissions stage which would provide an opportunity for NSPs to make submissions on stakeholder submissions made in relation to the draft determination and its revised regulatory proposal, as well as enable stakeholders to make submissions in response to each other's submissions. The content of those submissions would be confined to issues raised in stakeholder submissions which relate to the draft determination and / or revised regulatory proposal.

As noted above, the timing of the cross submissions stage would follow shortly after stakeholder submissions are made in respect of the revised regulatory proposal and draft determination. The ENA proposes that approximately three weeks (15 business days) after stakeholder submissions are made, cross submissions would be submitted.

A cross submissions stage would be a relatively minor adjustment to the decision making timetable and would greatly improve opportunities for stakeholder participation. The current Rules do not explicitly provide any opportunity for testing of the submissions made by the different parties by those with an alternative view. Introducing cross submissions will shift the emphasis in the regulatory process away from the AER acting essentially as the sole arbiter of the varying points of view on the revised regulatory proposal, towards an environment where there is wider debate between NSPs and stakeholders.[62]

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[61] Attachment F, p 30.
[62] Attachment F, p 34.

(c) Timing of the final determination

Bringing forward the final determination will provide more time for the finalisation of distribution prices (and consequently the incorporation of these prices by retailers in their prices) and in the case of transmission, the incorporation of transmission prices by distributors in their prices. This will mitigate roll-on effects on pricing proposals caused by any delays in the making of the final determination.

A delay of more than one to two weeks in the making of a final distribution determination would effectively delay the annual price change as there is only three weeks following the final determination before DNSPs are required to submit the annual pricing proposal, and then only two to three weeks for the AER to consider and decide whether or not to approve the pricing proposal.[63] The position is of slightly less importance in transmission. If the AER has not made a final decision by three months prior to the commencement of the first financial year that a pricing methodology is to apply, there are provisions which permit the TNSP to commence the setting of prices other than on the basis of the approved pricing methodology.[64]

Bringing forward the regulatory determination process extends what is referred to in the context of pass through events as the "dead zone". This is the time between the lodgement of a regulatory proposal and the commencement of the new regulatory period. Where a pass through event occurs during the dead zone which leads to costs being incurred in a subsequent regulatory period it may not be possible for a NSP to amend its regulatory proposal to take these changes in costs into account and nor is it possible to apply for a cost pass through with respect to that event in the following regulatory period. In this regard the ENA notes the Rule change proposal lodged by Grid Australia in October 2011 which deals with, among other things, the dead zone issue.[65] If the regulatory determination process is brought forward, the potential exposure to events that arise during the dead zone that cannot be factored into forecasts in the subsequent regulatory period is greater, which would further reinforce the need for the Rules to adequately deal with pass through events occurring in the dead zone.

Question 37: Are there any other options that could address the issue of providing adequate time for consultation and assessment during the regulatory process?

The ENA considers that the Rules should provide the basic framework for the various stages in the regulatory determination process but afford sufficient flexibility so that when issues arise, they can be dealt with by effective consultation between the AER, NSPs and stakeholders, without the need to resort to overly prescriptive rules.

As referred to in the annexed expert report, the need for effective communication outside the parameters of the Rules between regulatory participants is paramount in providing adequate time for consultation and assessment during the regulatory process.[66] The ENA adopts the suggestion that at the outset of a regulatory process, the AER should make it clear to the NSP its internal timelines, the extent (if any) to which the AER has resources constraints, and any particular issues on which the AER seeks stakeholder comments. Likewise, the NSP should signal any possible areas of uncertainty, and the potential for submissions.[67] NSPs should also seek to engage with the AER and stakeholders during the preparation stage of their proposal so that there is a common understanding of the key drivers underpinning the regulatory proposal, as well as to flag any potential issues anticipated to arise during the regulatory process.

In this way, the AER and NSP should work together to plan for and anticipate potential issues and problems, and then maintain an ongoing dialogue throughout the regulatory determination process.

[63] Clauses 6.8.2 and 6.18.8.
[64] Clause 6A.24.3.
[65] Grid Australia, *Rule Change Proposal – Cost Pass Through*, October 2011.
[66] Attachment F, pp 37 - 38
[67] Attachment F, p.32

In addition, the ENA considers that the adoption of a mandatory issues paper and guidelines on late submissions will further promote this objective.

(a) Issues paper

The ENA supports the AEMC's proposed mandatory issues paper to be published by the AER. Presently, an optional issues paper is provided for within the Rules following the regulatory proposal.[68] A mandatory issues paper would seek to facilitate better and more efficient engagement with stakeholders from the very outset of the regulatory determination process. In signalling the key issues to be considered as part of the forthcoming determination process, the AER will be encouraging more targeted and effective submissions and allocation of resources committed by stakeholders in scrutinising the initial proposal. The ENA submits that:

- the issues paper would not be binding on the AER, nor constrain its subsequent decisions; and
- any administrative cost implications would not be significant as it is likely that the AER forms a view of the key issues shortly after receiving the regulatory proposal so to inform their work plan. Therefore, an issues paper should reflect public work already undertaken, and not entail significant additional work for the AER.

(b) Guidelines dealing with late submissions

NSPs strive to provide full and complete proposals on the information and material available at the particular time. There are valid reasons why late submissions may be required due to some external event. A Rule which promotes the arbitrary exclusion of further material information will undermine pursuits for accurate and robust decision making, increasing risk of regulatory error.

The ENA supports the maintenance of the Rule providing the AER with discretion to deal with late submissions on a case-by-case basis. However, the ENA proposes that the AER and NSPs should consult with each other in developing non-binding guidelines to clarify expectations of NSPs in making submissions and the considerations the AER takes into account in exercise of its discretion. In particular, the guidelines would refer to the circumstances when a late submission *should* be taken into account by the AER, including when:

- the AER is proposing a material shift from its position in the draft decision to the final decision and the relevant matters have not been the subject of consultation; or
- information becomes available to the NSP that was not previously available or events occur which are outside of the control of the NSP, at the time when the NSP submitted any revised proposal / submission on the draft decision (for example, the outcome of a Royal Commission, or a change in legislation).

In relation to the first category of submission, it demonstrates the importance of the AER making available any material that it seeks to rely on to stakeholders as early as possible in the process to enable that material to be properly consulted on and responded to. In relation to the second category, it highlights the inevitability of certain material events, unforeseen or outside of the NSP's control, but which will have an impact on its business, and therefore should be reflected in the terms and conditions of the final determination. NSPs may also wish to provide submissions relating to some valid information or clarification that the AER may find helpful, is not controversial or minor and can easily be taken into account by the AER, without compromising other stakeholders rights.

[68] Clauses 6.9.3(b) and 6A.11.3.(b).

As recommended in the annexed expert report, the ENA adopts the following proposed guidelines in pursuit of best regulatory practice:[69]

- The AER would voluntarily undertake to have regard to such submissions 'as far as practicable'. That is, the AER would be obliged to take into account the submission to the extent it is practical to do so, including where the NSP and AER consult and agree upon a delay in the date for publication of the final determination.

- As a general position, delaying the final regulatory determination should be avoided, but not at the expense of properly dealing with a matter that is material to the making of the final determination.

- NSPs are to advise the AER as soon as practicable once it is aware that there is an issue that may give rise to a late submission. This practice would promote the necessary dialogue between the AER and the NSP to jointly plan on how best to address the issue in an efficient manner.

- The guidelines would clarify that the AER need not have regard to the submission, if it is received too late, or if the AER has inadequate resources, or a delay in the date for publication of the final determination is not agreed.

Having clarified how the AER will deal with late submissions, the AER can proceed on principled grounds to either accept or decline to have regard to a late submission.

Such non-Rule based initiatives provide clear incentives on the AER and NSPs to approach issues which inevitably arise within the regulatory determination process jointly and in a conciliatory manner.

7.4 Claims for confidentiality

The ENA endorses an approach to confidentiality claims which balances the legitimate rights of NSPs to maintain confidentiality of certain information and the rights of other stakeholders in having access to confidential information in circumstances where that information should be subject to scrutiny. The ENA considers that the adoption of non-rule based solutions such as a confidential information protocol and standard form confidentiality undertakings best achieves this balance.

7.4.1 The current National Electricity Rules

In summary, under the NER:

- DNSPs must indicate parts of their regulatory proposal they claim to be confidential and wish to have suppressed from publication on that ground.[70]

- The AER must publish initial and revised regulatory proposals, but is not permitted to disclose confidential information unless disclosure is permitted by the NEL and the NER.[71]

- For *submissions* containing information identified as confidential, the AER may give such weight to confidential information as it considers appropriate.[72] There is no equivalent provision in the NER with respect to confidential information in an NSP's initial and revised regulatory proposals.

- Disclosure of information given to the AER is authorised in certain circumstances prescribed under the NEL[73] or the common law.

[69] Attachment F, p.36
[70] Clause 6.8.2(c)(6).
[71] Clauses 6.9.3(a), 6.10.3(d), 6A.11.3(a) and 6A.12.3(f).
[72] Clauses 6.14(e) and 6A.16(e).

7.4.2 AEMC's initial position

In the Directions Paper the AEMC commented that:

- It is unlikely that all aspects of an initial or revised regulatory proposal could legitimately be claimed to be confidential, bearing in mind that NSPs are monopolies and therefore do not compete directly with other businesses. Only small parts of initial or revised regulatory proposals should be claimed as confidential.
- The AER's discretionary powers under the NEL and common law to determine the weight to be given to confidential information may be utilised.[74]
- Aggregating of information might be appropriate where confidentiality concerns are raised.[75]
- It might be appropriate to consider an extension of time period to allow the AER sufficient time to assess claims of confidentiality.

7.5 Answers to specific questions

Question 38: Should the AER be given more time to consider confidentiality claims in initial and revised proposals?

The ENA supports the AEMC's view that only genuinely confidential parts of initial or revised regulatory proposals should be the subject of confidentiality claims. However, on the basis of experience to date it is not clear that the AER requires more time to consider confidentiality claims. The AER mainly takes issue on *what* and *how much* is being claimed as confidential by NSPs. To the extent there is a perceived concern about the time pressures to assess confidentiality claims, addressing issues as to the amount and form of confidentiality claims should address the concerns about the time constraints.

The ENA submits that effective implementation of the confidential information protocol, as discussed below, will represent a superior solution to address any perceived inefficiencies in the process for dealing with confidentiality claims.

Furthermore, the ENA does not object to the AER's proposed amendment to the Rules requiring NSPs to *identify* parts of the initial or revised regulatory proposal that are claimed to be confidential, if the AEMC are of the opinion that that will achieve a greater level of specificity within confidentiality claims.[76]

In any case, the AEMC states that the AER appears to have existing powers under the NEL and common law to use discretion in determining the weight to be given to confidential information in initial and revised regulatory proposals. The AER indicates that while the current time frames make it infeasible to apply the public interest tests under section 28ZB of the NEL, its internal processes are being improved upon to allow it sufficient time to make use of this discretionary power.

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[73] NEL, sections 28X, 28ZA, 28ZAB, 28ZB.
[74] *National Electricity (South Australia) Act 1996* (SA), s 28ZB . In summary, section 28ZB authorises the AER to disclose confidential information when it is satisfied that such disclosure would not cause detriment, or if it will cause detriment, the public benefit outweighs the detriment. The AER has indicated that its internal processes are being improved upon to allow it sufficient time to make use of the discretion power.
[75] AEMC *Directions Paper* (2012), p.136
[76] AER draft clauses 6.8.2(c)(6), 6.8.10.3(c1), 6A.10.1(g) and 6A.12.3(e).

Question 39: Should the NER be clarified to reflect the NEL and/or common law position with respect to the AER's ability to give weight to confidentiality claims in initial and revised regulatory proposals?

Treatment of confidential information necessarily involves balancing the interests of the party submitting the confidential information, the interests of other stakeholders in being able to interrogate this information and the robustness of the decision making process. To the extent that the AER perceives any problem with the current arrangements for treatment of confidential information, non-Rule based alternatives such as limited disclosure schemes are to be preferred over simply discounting the value of probative confidential information.

There is a clear public interest in transparent decision making. However, as considered below, disregarding valuable information in compromise of the quality of the final determination is clearly not the least cost way to maximise transparent decision making.

The common law requires that the AER is required to consider a whole range of material and evidence, including confidential information that is relevant to the making of the administrative decision in question.[77] While the AER lacks an explicit statutory power to determine the appropriate weight to be given to information subject of a confidentiality claim, it is implicitly open to the AER to weigh all material and information, including confidential information by reference to the level of testing or scrutiny it considers is required, and whether that required level of testing or scrutiny has occurred. Should the AER have before it confidential information material to a determination, the public interest exceptions provided in the NEL and the common law will permit appropriate third party access and testing of information if so required. To the extent that there is a perceived problem, facilitating greater reliance by the AER on its existing powers to compel the disclosure of confidential information would clearly be a preferable alternative to the AER Rule change proposal. Further options open to the AER would include the adoption of limited third party disclosure agreements, which would form part of the confidential information protocol initiative considered below.

The AER has not made a case to suggest that there have been occasions where there has been confidential information claimed and the absence of public scrutiny has prevented the AER from properly assessing the weight that should be afforded to that information.[78] Following this, the ENA does not consider that there would be benefit in clarifying the NER to reflect the NEL and/or common law position with respect to the AER's ability to give weight to confidentiality claims in initial and revised regulatory proposals.

Question 40: Alternatively, are there any other additional ways to address confidentiality claims in initial and revised regulatory proposals that are not currently available under the NER?

The NER must balance the conflicting objectives of providing scope for testing and scrutiny of initial or revised regulatory proposals as much as possible, while upholding legitimate claims of confidentiality made by NSPs.[79] To achieve this balance and to improve the management of confidential information, the ENA propose the adoption of a confidential information protocol.

The ENA promotes an approach to addressing claims of confidentiality which facilitates dialogue between the AER and the NSP at the initial and revised proposal stages to ensure that claims can be dealt with swiftly and efficiently, and to ensure that all relevant information is considered by the AER in pursuit of best regulatory practice.

Non-Rule based solutions in relation to confidential information would be the best way to address any perceived concerns around blanket confidentiality claims and insufficiency in time for the AER to process

[77] See *Minister for Aboriginal Affairs v Peko Wallsend Ltd* (1986) 162 CLR 24.
[78] ENA's December 2011 Response to Proposed Rule Changes, Annexure - Gilbert + Tobin Report, p.15
[79] AEMC *Directions Paper* (2012), p 135.

them.   As commented in the export report, an 'AER led process for developing the guidelines would foster improved understanding and credibility for the arrangements, and is like to create more certainty and lower regulatory costs than other options'.[80]

A confidentiality protocol complements the NEL provisions on confidentiality in making available confidential information for testing and scrutiny by stakeholders while preserving genuinely confidential information.[81] It would clarify the approach to be taken to confidential information by NSPs and the AER, and operate to facilitate the disclosure of confidential information where appropriate on a restricted or controlled basis.   Such limited disclosure regimes are commonly used by regulators in other industries. For example, in telecommunications, the ACCC typically negotiates with carriers for limited release of confidential information to third parties, subject to those third parties executing appropriate confidentiality undertakings. The standard non-disclosure undertaking could be based upon a standard form document which builds upon the AER Confidentiality Guidelines for Dispute Resolution[82] or alternatively the undertaking could take the form of a modified version of the Confidentiality Deed contained in those Guidelines.[83]

Key elements of the proposed confidential information protocol include:

1. In general NSPs will seek to provide a regulatory proposal document where confidential information is contained in attachments to the main proposal document so that there is no need for redactions of parts of the main regulatory proposal.

2. Where the main regulatory proposal document does contain confidential information, NSPs will provide the AER with a version which can be published (i.e. with confidential information redacted or deleted) at the same time or as soon as practicable after the proposal has been lodged.

3. In relation to attachments and other parts of the regulatory proposal which are confidential, where appropriate NSPs will provide the AER with a version which can be published. However in some cases it may be that the whole of an attachment will be the subject of a confidentiality claim.

4. In all cases NSPs will clearly identify in relation to each part of the proposal those elements which are confidential and the basis of that claim by reference to agreed / recognised categories of confidential information.

5. The same approach will be taken in relation to revised proposals and any information provided to the AER in response to a request for information, formal or otherwise.

6. To facilitate the broader consideration and testing of confidential information NSPs will work with the AER and stakeholders to agree to the disclosure of confidential information to stakeholders where appropriate undertakings can be given in relation to the use and application of that information. For example information could be made available to consultants, retained by consumer groups to analyse information so that a model or approach can be understood and explained to stakeholders. As noted in the expert report by Geoff Swier provided with this submission, this option appears to have the 'best potential to address the underlying issues (the need for improved quality and relevance of probative information provided to the AEMC) by enabling access to all confidential information by stakeholder representatives and experts'.[84]

7. To ensure that information which has been accepted / treated as confidential by the AER is not inadvertently disclosed in a draft or final determination, the AER will provide the NSP with a

[80] Attachment F, p.43
[81] *National Electricity (South Australia) Act 1996* (SA), Part 3, Division 6.
[82] AER, Confidentiality Guidelines for Dispute Resolution under Rule 8.2 of the National Electricity Rules, November 2009.
[83] AER, Confidentiality Guidelines for Dispute Resolution under Rule 8.2 of the National Electricity Rules, November 2009, Attachment – Template Confidentiality Deed, p.8
[84] Attachment F, p 48

reasonable opportunity (at least 48 hours) to review the draft or final determination to ensure that it does not disclose any confidential information.

The confidential information protocol would also provide a process for NSPs to disclose the basis for making the claim of confidentiality via the identification of the particular category that the confidential information falls within. The following categories of confidential information are proposed (subject to a possible additional, catch-all category):

- *Confidential contractual terms*, the disclosure of which is likely to put the NSP in breach of contract or would adversely impact on its contractual compliance. This is most likely to arise where a counterparty has requested that all or parts of the contract be kept confidential but may also arise in relation to contracts of insurance with respect to such matters as insurance layers and excess levels. Examples of these types of agreements are access agreements for the National Broadband Network and insurance contracts.

- *Market sensitive cost inputs* such as supplier's prices and internal labour costs, the disclosure of which may adversely impact upon the NSPs ability to negotiate the most efficient price or rate for goods and service or its ability to compete in a competitive market for distribution services.

- *Information provided by a third party on a confidential basis* the disclosure of which would adversely affect the interests of that third party or the public interest more generally. For example proposed major connections, proposed public infrastructure development, not currently in public domain.

- *Proposed strategic property acquisitions* for the transmission or distribution system, for example easements for lines and purchases for substations, the disclosure of which is likely to adversely impact on the NSP's ability to negotiate a fair market price for the acquisition.

- *Planning for negotiation of industrial agreements*, where disclosure of such information is likely to adversely impact upon the NSP ability to negotiate industrial agreements.

- *Proprietary information of NSP or a third party* e.g. sophisticated models developed at significant expense to NSP either itself or by its consultant. This is the type of confidential information that might be subject to disclosure if suitable undertakings have been given which protect the proprietary or commercially sensitive nature of the model.

- *Information which if made public may jeopardise security of the network or NSPs ability to effectively plan and operate its network* e.g. Network Security Arrangements, Emergency Response plans include Terrorism Response Plans.

- *Information which identifies the personal affairs of individuals* e.g. terms and conditions of employment relevant to individual employees.

7.6 Framework and approach paper process

The ENA considers that the framework and approach paper (**FAP**) process should not be a mandatory step in the making of a distribution determination. Rather, a FAP process should be undertaken in specified circumstances where there is an identified need for a preliminary consultation step prior to the DNSP finalising its regulatory proposal for submission to the AER. In broad terms, a preliminary consultation step is appropriate where:

- there is no current distribution determination in place in respect of the relevant distribution network; and

- where there is a current determination in place but:

  - either the DNSP or the AER will be proposing a material departure from a relevant element of that distribution determination in the upcoming distribution determination process (for example, the form of the control mechanism to apply or the service classifications that were applied); and / or

  - the existing distribution determination does not deal with a matter that has now become relevant, perhaps as a result of a change in circumstances (for example, when the previous determination was made a DNSP did not have dual function assets, but now does).

The ENA proposes that the relevance of the triggering of the FAP process would be the following:

- if a FAP process is triggered, there may only be departure from the matters addressed in the FAP in the final determination if a departure has been sought by the DNSP and the DNSP has provided material that justifies the departure;

- if no FAP process is triggered, no departure from the approach taken to the relevant matters in the distribution determination that applied in the immediately prior regulatory period under the ENA's proposal is permitted.

A minor exception to the above would be to permit departures in respect of the formulaic expression of the control mechanism where appropriate.

7.6.1 The current National Electricity Rules

The steps set out below are relevant to the FAP process and its effect.

- The AER must prepare and publish a FAP.[85]

- The FAP discloses the AER's likely approach to classifying distribution services, application of certain incentive schemes and any other matters on which the AER thinks fit to indicate its likely approach[86] and the form of control mechanism for each service.[87]

- In respect of the classification of services set out in the FAP, this may be departed from during the regulatory determination process if there are good reasons for doing so.[88]

- The AER's application of certain incentive schemes and any other matters the AER thinks fit to set out in the FAP are not binding on the AER or DNSP.[89] The control mechanisms set out in the FAP are, however, binding[90].

- Preparation and consultation on the FAP must commence at least 24 months before the end of the regulatory control period. Publication of the FAP must be at least 19 months before the end of that regulatory control period.[91]

[85] Clause 6.8.1(a).
[86] Clause 6.8.1(b).
[87] Clause 6.8.1(c).
[88] Clause 6.12.3(b).
[89] Clause 6.8.1(f).
[90] Clause 6.12.3(c).
[91] Clause 6.8.1(f).

7.6.2 AEMC's initial position

The AEMC made the following preliminary comments on the FAP:[92]

- The FAP stage should be optional, with the appropriate trigger to be considered further.
- Incentive schemes should remain part of the FAP. It may be appropriate to include in the FAP the proposed sharing mechanism to allow consumers to be compensated where distribution assets are used to provide non-standard control services. The AER's concern with incentive schemes may be alleviated if the FAP stage is made discretionary.
- The AER's proposal to use 'unforeseen circumstances' as the trigger for allowing changes to a control mechanism or service classification set in the FAP appears to be broadly appropriate from a policy point of view. The AEMC seeks submissions on this, and in particular whether any foreseeability element must be reasonable.
- The trigger for a departure from the control mechanisms should, if possible, be the same as that for the service classification.
- More information is sought on how much time it is likely to take for a DNSP to adjust its regulatory proposal for a revised control mechanism set by the AER in a draft regulatory determination.

7.7 Answers to specific questions

Question 41: Should the framework and approach paper be a discretionary stage in the distribution regulatory determination process?

The FAP stage should be optional other than in circumstances where there is no distribution determination currently in force and applying to the relevant DNSP.

If a distribution determination does currently apply to the DNSP, then the ENA considers that unless there is a material change proposed by either the DNSP or the AER to identified components of that distribution determination, then it should not be necessary for there to be consultation on that particular component, and, no requirement at all for any FAP.

That is, the FAP should not be mandatory once a DNSP has in place a distribution determination (that is, once the DNSP has been through a full distribution determination process under the Rules and a FAP has already been undertaken). Under this proposal, a FAP is only required; and its scope should be defined, where there are issues concerned with changes to control mechanisms, incentive schemes, service classification or dual function assets or there is an adjustment for the use or forecast use of assets or adjustment to building blocks.

Questions 41 and 42: If the framework and approach paper is discretionary, what is the appropriate approach to triggering it? Is it appropriate if a service classification or control mechanism can only be amended at the time of an AER final regulatory determination for circumstances that were not reasonably foreseeable at the time of the framework and approach paper?

The ENA considers that the Rules should provide appropriate mechanisms for triggering the commencement of the FAP, as well as changes to certain components of the FAP during the regulatory process.

[92] AEMC *Directions Paper* (2012), p.141-143

The ENA considers that the FAP process should not be a mandatory step in the making of a distribution determination. Rather, a FAP process should be undertaken in specified circumstances where there is an identified need for a preliminary consultation step prior to the DNSP finalising its regulatory proposal for submission to the AER. In broad terms, a preliminary consultation step is appropriate where:

- there is no current distribution determination in place in respect of the relevant distribution network; and
- where there is a current determination in place but:
  - either the DNSP or the AER will be proposing a material departure from a relevant element of that distribution determination in the upcoming distribution determination process (for example, the form of the control mechanism to apply or the service classifications that were applied, the application of incentive schemes, the specification of dual function assets, or use or forecast use of assets or building blocks); and / or
  - the existing distribution determination does not deal with a matter that has now become relevant, perhaps as a result of a change in circumstances (for example, when the previous determination was made a DNSP did not have dual function assets, but now has some).

Changing circumstances in the business of the DNSP may require departure from components expressed, or not otherwise provided for, in the distribution determination currently in force to keep it in step with those changes. If the AER or DNSP consider that there are material changes to be accommodated, the FAP process can be initiated by that notice, with no further threshold to be satisfied.

Specifically, in respect to incentive schemes, the ENA adopts the observation that there is now a considerable degree of maturity as to how the incentive schemes should operate.[93] Therefore, a mandatory requirement to consult on incentive schemes in the FAP is unnecessary. Consultation should be required only when the AER or DNSP consider that a review of the application of an incentive scheme that currently applies is warranted.

Notice of any material change should be provided a sufficient time prior to the end of the current regulatory control period so that proper consultation on the issues can be facilitated and the publishing of the FAP can be programmed into the work plan of the AER.

The ENA would propose that the relevance of the triggering of the FAP process would be the following:

- if a FAP process is triggered, there may only be departures from the matters addressed in the FAP in the final determination if a departure has been sought by the DNSP and the DNSP has provided material that justifies the departure;
- if no FAP process is triggered, no departure from the approach taken to the relevant matters in the distribution determination that applied in the immediately prior regulatory period is permitted.

A minor exception to the above would be to permit departures in respect of the formulaic expression of the control mechanism where appropriate.

To accommodate for changes in the circumstances of the business and operation of DNSPs, the Rules should operate flexibly and facilitate review of, and changes in service classifications and / or the form of control mechanism where justified. Legal threshold tests which incorporate a foreseeability criterion introduce uncertainty and ambiguity into the regulatory process. Where material change occurs, the Rules should accommodate that change, not obstruct it. For instance, there are a number of pressures

[93] Attachment F, p 48

to review service classifications arising from changes in the DNSP environment including developments in smart meters and related services, demand management, embedded generation, or changes in opportunities for contestability at the margins of DNSP operations.[94] Best regulatory practice should 'allow for innovation and adaptation to changing circumstances' rather than tie change to technical legal concepts.[95]

The ENA submits that the test for departure from the classification of services or the form of the control mechanisms in the relevant FAP should occur when the DNSP provides material (i.e. in the form of the regulatory proposal or submissions) that justifies the departure. The AER would be left with a residual discretion to reject the DNSP's proposed change if the material does not support the departure sought. The attraction of this test is that it is easy and simple to apply, and looks to the probative matter in issue – does the material provided support a change in the components specified in the FAP? Questions of foreseeability only distract from the relevant inquiry.

The ENA supports stakeholder views that the AER should in making changes to the control mechanism, be limited to changes in the formulaic expression of the control mechanism.[96] The failure to 'lock in' at the FAP at least the type of the control mechanism to apply creates an unacceptable degree of regulatory uncertainty for DNSPs and potentially imposes a prohibitive administrative burden on DNSPs to properly assess any new proposed type of control mechanism given the temporal constraints in place after regulatory proposals have been submitted.[97]

Question 41: Should stakeholders other than NSPs have the ability to trigger a framework and approach paper?

The Rules should provide that only the AER or the relevant DNSP should be permitted to trigger a FAP process by relevant notice being provided. However, good regulatory practice demands that the AER would take into account the interests of stakeholders about the requirement for, or continued relevance of a FAP. For instance, currently, when considering service classification, the AER must have regard to the potential for development of competition in the relevant market and how the classification might influence that potential.[98] There may be third parties (for example electrical contractors in regard to contestability opportunities)[99] who seek changes to service classifications. The Rules do not need to prescribe this consultation with third parties, but a conciliatory approach would be expected in pursuit of credible and robust decision making.

Question 43: Is there likely to be sufficient time for a NSP to accommodate an adjustment to a control mechanism in an AER draft regulatory determination?

The amount of time it is likely to take for a NSP to adjust its regulatory proposal for a revised control mechanism set by the AER in a draft regulatory determination depends largely on the nature and scope of the adjustment. As referred to in the annexed expert report on regulatory process and practice, the types of analysis required by a DNSP to adjust its regulatory proposal in response to a revised control mechanism could, depending on the nature of the change, include:[100]

[94] Attachment F, p 50
[95] Attachment F, p 50
[96] ETSA Utilities, Citipower and Powercor Australia, *Joint Response to AER and EURCC Rule Change Proposals,* 8 December 2011, p 37.
[97] Ibid.
[98] Clause 6.2.2(c)(1).
[99] See for example s 2.4.2 of AER Final decision, *Framework and approach paper Classification of services and control mechanisms* Energex and Ergon Energy 2010-15. The AER noted that 'Submissions received from design consultants and construction contractors indicate that there are alternative providers available in Queensland to provide the design and construction of large connection assets service but the market was constrained due to the DNSPs limiting the entry of alternative providers to the market.' Potential for such competition may evolve over time.
[100] Attachment F, p.61

- analysis of the change on revenues and returns of any changed risk allocation, in particular demand risk;

- analysis of the desired change in the tariff for the services that are subject to the control mechanism; and

- potentially, operational effects (for example, if changes in tariffs have significant operational implications).

It is unlikely that there will be sufficient time to accommodate material changes to a control mechanism, but there may be time (and there should be flexibility) to amend the formulaic expression of the control mechanism as stated above. Minor refinements in the price control formula can be dealt with quite quickly; whereas a fundamental change in the price control (for example moving to a hybrid price / revenue cap) would take much longer.[101]

The ENA endorses an approach to the FAP which ensures that DNSPs and the AER are in consultation to determine an appropriate process and time frame to accommodate the particular circumstances. This consultation objective need not be prescribed in the Rules, rather good regulatory process and practice would see that the AER and DNSPs would openly communicate on issues concerning the preparation of, or change to the FAP. Flexibility in the Rules would require:

- early consultation between the NSP and AER at the outset of the determination process to determine whether there is a possibility of revisions to the FAP and also targeted stakeholder consultation to ascertain whether there is any perceived need for a review; and

- based on the nature of the possible change either identified at the outset of the regulatory process, or during the regulatory process, the AER and NSP would be required to consult on and agree a decision timetable.

7.8 Material errors in regulatory determinations

The ENA supports an approach to the Rules which clearly specifies the circumstances under which the AER may revoke and remake a regulatory determination as a result of a material error in order to increase certainty and transparency associated with the regulatory regime and enhance incentives for NSPs to provide the most accurate and relevant information. The ENA considers that the Rules as presently expressed in relation to revocation and substitution for material errors should remain largely unamended. The AER has not identified any deficiency in the existing Rules in relation to the correction for material errors. There is no present need for the amendments proposed by the AER.[102]

7.8.1 The current National Electricity Rules

In summary, presently under the NER:

- The AER may revoke a regulatory determination during the regulatory control period to correct for material errors.[103]

- For transmission, revocation is possible when the regulatory determination is set on the basis of false or materially misleading information, or where there is a material error (although ‘material error’ is not defined in the NER).[104]

[101] Attachment F, p.51
[102] ENA’s December 2011 Response to Proposed Rule Changes, p.65-68
[103] Clauses 6.13 and 6A.15.

- For distribution, the material errors or deficiencies for which the AER may revoke and substitute a regulatory determination are more prescriptive. In particular, material errors or deficiencies are defined by reference to certain categories, including clerical error, an accidental slip or omission, a miscalculation or misdescription, a defect in form, or the regulatory determination is based on false or misleading information provided to the AER.[105]

- If the AER revokes a regulatory determination, it must make a new regulatory determination in substitution for the revoked regulatory determination, to apply for the remainder of the regulatory control period.[106] If it is as the result of a material error or deficiency, the substituted regulatory determination must only vary from the revoked regulatory determination to the extent necessary to correct the relevant error or deficiency.[107]

7.8.2 AEMC's initial position

Broadly speaking, the AEMC's view is that to promote the objective of finality in regulatory determinations, changes should only occur as a result of merits review outcomes or in very clear and exceptional circumstances.

The AEMC's initial position to the Rule change concerning materials errors is that:[108]

- the 'only to the extent necessary' limitation should apply to false and misleading information under Chapter 6A – this would align Chapter 6A with Chapter 6 and provide certainty and finality;

- it is unclear how amending regulatory determinations would differ in practice from revoking and substituting – but the AEMC agrees that this will impact unfavourably on the availability of merits reviews;

- more support is required prior to broadening the types of material errors or deficiencies under Chapter 6 by which the AER may revoke and substitute regulatory determinations. The AEMC is in favour of keeping the scope of material error provisions narrow and focussed on 'computational' errors or situations where a NSP has submitted false or misleading information. Provisions such as cost pass throughs, capex reopeners and contingent projects are the appropriate means by which more substantive changes to the regulatory determination should be made; and

- it may be more appropriate for Rule 6A.15 to reflect the narrow scope of material errors in Rule 6.13 – this would result in more certainty and finality for the AER and NSPs, although less flexibility for the AER.

7.9 Answers to specific questions

Question 44: Should the material error list under Chapter 6A be amended to reflect the current prescribed list under Chapter 6 of the NER?

The ENA submits that there is no evidence to suggest that the current drafting of the revocation and substitution provisions that apply in Chapter 6A are inappropriate. The AER has not identified a circumstance in which it considers it should have been able to revoke and substitute a particular transmission determination but was not able to do so.

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[104] Clause 6A.15(a).
[105] Clause 6.13(a).
[106] Clauses 6.13(b) and 6A.15(b).
[107] Clauses 6.13(c) and 6A.15(c).
[108] AEMC *Directions Paper* (2012), p.146-147.

The drafting of the correction for material error provisions in Chapter 6 and Chapter 6A is different. However, that difference is understandable given the Chapter 6 provisions encompass 'deficiency' (and therefore the prescribed list is appropriate to give certainty in relation to what matters may be considered to be a 'deficiency') and the Chapter 6A provisions do not. Unless the AEMC considers that the Chapter 6A provisions should encompass 'deficiency' (and the ENA does not consider that Chapter 6A should be amended to also refer to deficiency), there is no need for the material error list in Chapter 6A to be amended to reflect the current prescribed list under Chapter 6. If the AEMC was to give any consideration to amending Chapter 6A to include a power to correct for a 'deficiency' the prescribed categories of 'material error or deficiency' would need to be reflected in Chapter 6A to adequately define the scope of that expression.

Question 45: Has the AER been constrained by the wording of Chapter 6 of the NER in its approach to revoking and substituting regulatory determinations as a result of material errors or deficiencies?

The ENA does not consider that there is any evidence that the AER has in anyway been constrained by the wording of Chapter 6 of the NER in its approach to revoking and substituting regulatory determinations as a result of material errors or deficiencies.[109] As noted above in response to question 44, insofar as the AER seeks to remove the prescribed list of material errors in Chapter 6, and include the term 'deficiency' as a source for revocation and substitution, the ENA submits that those Rule change proposals are unnecessary, and not supported by evidence.

The ENA considers that the prescribed list of errors in Rule 6.13(a) appropriately covers the types of errors that the AER should be able to correct for. This list strikes an appropriate balance between allowing correction of clerical and typographical types of errors, while maintaining certainty as to the finality of the determination. The AEMC has a clear policy intent in drafting the current Rule 6.13(a). The AEMC stated that Rule 6.13(a):

> ...should ensure sufficient certainty with respect to the term 'material error', and
>
> acknowledge that the use of 'material error' is a well established term in law and constituted a material error of fact rather than judgement to ensure that revocation would only occur where it falls within the legal bounds of a 'material error' [110]

In the ENA's December 2011 submission, a review of distribution and transmission determinations, including transmission determinations made by the ACCC under the National Electricity Code which included a similar provision for correction of errors to that in Chapter 6A, did not indicate that there have been circumstances in which the AER or ACCC considered that it would have been desirable to revoke and substitute a determination, but it did not have the power to do so.[111] The accompanying Gilbert + Tobin Report – *Assessment of proposed changes to regulatory decision making process under the National Electricity Rule* to the ENA's December 2011 submission, disclosed that in respect of distribution determinations, there have been circumstances where a NSP has requested the AER to exercise its power to revoke and substitute a regulatory determination, but the AER has declined to do so, and the NSP ultimately had to seek merits review of the error.[112] These reviews undertaken do not suggest that there is any inefficiency in the current process, or that the AER has been constrained in its ability to respond to, and correct for, material error or deficiency. Conversely, on occasions where it has been open to the AER to exercise its power to correct for error, it has not done so.

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[109] ENA's December 2011 Response to Proposed Rule Changes, pp 65 - 67.
[110] Ibid.
[111] ENA's December 2011 Response to Proposed Rule Changes, Annexure - Gilbert + Tobin Report, pp 23 - 24.
[112] Ibid, p 24.

Others issues addressed

Given the significant impact that the AER's proposal to include an ability to amend, in addition to revoke and substitute regulatory determinations, will have on the availability of merits review, the ENA reiterates its comments made in its December 2011 submission.

The ENA considers that the power to amend will have the affect of removing safeguards for review of decisions that exist in the current provisions. In particular, the making of a new distribution or transmission determination to apply for the remainder of the regulatory control period would be a reviewable decision within the scope of the merits review provisions, whereas it is unclear whether a decision to 'amend' would be a reviewable decision. It would be inappropriate to implement rule changes if the only, or major, effect would be to reduce rights to merits review.[113]

As already noted, the ENA's December 2011 submission highlighted that under equivalent provisions in the National Electricity Code, the requirement to revoke and substitute decisions has not operated as a significant barrier to correct for error.[114] In the absence of the AER providing evidence to the contrary, the process for 'revoking and substituting' versus the process for 'amending' would be the same given the potentially significant consequences of the AER amending a determination. Therefore, there is no apparent administrative benefit in including a power to amend.

If the AEMC is of the view that a power to 'amend' will in some way enhance the objectives of the NEL, than the ENA submits that the exercise of any amending power must be subject to the requirement of the consent of the relevant NSP. If an amendment of a regulatory determination will in some way limit a NSP from applying for a merits review of the decision, then a consent requirement is necessary to afford procedural fairness.

7.10 Time frames for cost pass through, contingency projects and capex reopener applications

Time frames for cost pass through, contingency projects and capex reopeners should seek to efficiently manage the risk and uncertainty arising from complex or exceptional circumstances. The Rules should provide the basic framework for affording flexibility to accommodate such circumstances. Appropriate consultation outside the parameters of the Rules should be adopted by the AER, NSPs and interested stakeholders so that the AER is made aware (if possible) that the making of such an application is intended. NSPs would also expect to be informed on the AER's proposed process to deal with the issues arising from any application, and openly engage with NSPs and stakeholders on complexities they encounter, as well as providing any reasons for any delay it envisages in the making of the determination.

7.10.1 The current National Electricity Rules

- For distribution and transmission, the AER has 60 business days to make a decision on a positive pass through application from when it receives the application.[115] There is currently no set time frame for the AER to make a decision on negative cost pass through applications.[116]
- In addition, for transmission, the AER has:
  - 30 business days to make a decision on a contingent project application from when it receives the application;[117] and

[113] Ibid, p 25.
[114] ENA's December 2011 Response to Proposed Rule Changes, Annexure - Gilbert + Tobin Report, pp 23 - 24.
[115] Clauses 6A.7.3(e) and 6.6.1(e).
[116] Clauses 6A.7.3 and 6.6.1.

– 60 business days to make a decision on a capex reopener application from when it receives it.[118]

- In distribution, the AER is required to extend the time for pass through applications if it is satisfied certain circumstances have been met.[119]

7.10.2 AEMC's initial position

The AEMC's initial position to the Rule change concerning time frames for cost pass through, capex reopeners and contingent applications is that:[120]

- Extending the time for the AER to consider the application to a specified period for complex circumstances, as the AER proposes, may be appropriate in some applications and provide a degree of certainty and finality.

- Where as an extension of time mechanism may be insufficient in circumstances, the 'stop the clock' mechanism proposed by NSPs would better cater for the risk that a prescribed maximum period is going to be exceeded.

- The 'stop the clock' mechanism may be appropriate for addressing complex pass through and capex reopener applications. However, it should not be applied to contingent project applications as it is unclear when complex circumstances could arise for these types of applications.

7.11 Answers to specific questions

Question 46: What should be the approach for addressing complex cost pass through, capex reopener or contingent applications? Is the "stop the clock" mechanism appropriate for each type of application?

The ENA agrees that the fixed time frames set out in the NER may not be sufficient in all cases for assessing complex cost pass throughs, capex reopeners or contingent project applications. Therefore, changes in the Rules to accommodate extended periods within which to consult and gather information is not unreasonable.

To address this issue the ENA supports the use of a 'stop the clock' mechanism for cost pass throughs, capex reopeners and contingency projects under which the AER has the power to 'stop the clock' on the period fixed for making a decision in respect of the application in circumstances where the AER:

- has invited written submissions to be made in respect of the application;

- makes requests for further information; or

- is awaiting other administrative processes which will impact the assessment or quantification of the application (i.e. awaiting the outcome of a related third party inquiry).

Any stopping of the clock on the assessment process would be limited to the time that is absorbed by waiting for receipt of information, consulting or waiting for the related inquiry to be concluded. The Rules

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[117] Clauses 6A.8.2(d).
[118] Clauses 6A.7.1(c)(2).
[119] Clauses 6.6.1(k).
[120] AEMC *Directions Paper* (2012), p.150-151

would prescribe that the AER must notify the NSP when the stopping clock mechanism commenced and ended.[121]

The AEMC is of the view that while 'stop the clock' is appropriate for cost pass through and capex reopener applications, it should not apply to contingency projects. The ENA submits that while some of the decision making in relation to these projects will have been done in the regulatory determination process itself, the AER's assessment of an application to amend a revenue determination where a trigger event for a contingent project has occurred is not limited to just whether the trigger event has occurred, but also:

- the amount of capital and incremental operating expenditure that is reasonably required for undertaking the contingent project;
- the total capital expenditure which is reasonably required; and
- the incremental revenue which is likely to be required by the TNSP in each remaining regulatory year as a result of the contingent project being undertaken (Rule 6A.8.2).

The AER is also (appropriately) required to consult and consider submissions on a range of matters (clause 6A.8.2(g)). Therefore, it may be appropriate to consider a 'stop the clock' mechanism also for contingent projects to facilitate proper and focussed consultation on the above issues with TNSPs, the AER and other relevant stakeholders.

The approach considered above is a superior solution as it targets the particular problems identified by the AER in its proposal. It will better promote the National Electricity Objective by:

- facilitating sufficient engagement by NSPs and interested parties together with the AER to consult upon relevant issues subject of the determinations; and

- extending the time frame for a decision on a particular application after adjusting the calculation of the time frame by the 'stop the clock mechanism'. This will ensure that the time frame can be extended beyond 100 business days where it is necessary to do so.

The ENA does not consider that the Rules should codify a process for NSPs to notify the AER of its intention to make an application. It would be overly prescriptive and inflexible to mandate that NSPs provide notice before a certain specified period before the making of the application. It would be more appropriate for the AER in consultation with NSPs, together with stakeholder input, to develop guidelines to clarify expectations of NSPs and the AER. In particular, the guidelines would clarify expectations of NSPs in notifying the AER of its intention to make an application, the form and content of the application, its role in assisting with further information, as well as the expectations of the AER in indicating the manner and process it will employ to deal with such issues, engaging in open consultation on complexities, as well as providing reasons for any delay it envisages.

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[121] At present, Chapter 6 does not contain provisions for capex reopener and contingent projects, if the AEMC were minded to include such provisions, the submission of the ENA in relation to Chapter 6A would apply equally.

ENA submission – 16 April 2012

Attachments A and B

Attachment A – NERA Economic Consulting Report – Analysis of Key Drivers of Network Price Changes (101 pages)

Attachment B – NERA Economic Consulting Report – Rising Electricity Prices and Network Productivity: a Critique (35 pages)

Attachment A

NERA Economic Consulting Report

Analysis of Key Drivers of Network Price Changes

NERA
ECONOMIC CONSULTING

Analysis of Key Drivers of Network Price Changes

A report prepared for the ENA

16 April 2012

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Executive Summary

The primary focus of this report is on analysing the extent to which network price changes for both electricity transmission and distribution network service providers (NSPs) in the current regulatory period have been the result of changes in the revenue requirements for NSPs arising from changes in WACC and increases in forecast capex and opex allowances. We have also identified the change in the NSPs' revenue requirement due to 'other factors', outside of the increase in WACC, capex and opex.

Further, we have examined the key drivers behind the increases in WACC and forecast capex and opex allowances, and considered the extent to which they reflect changes in circumstances which have been recognised as legitimate by the AER, rather than indicating shortcomings with the current regulatory framework. We note that NERA has prepared a separate report for the ENA covering the policy intent of the Chapter 6A Rules, and whether the AER's determinations under Chapter 6A are consistent with that policy intent.[1]

Specifically, this report is responding to the Australian Energy Market Commission (AEMC's) call in its Directions Paper in relation to the AER's Rule change proposal for further evidence 'on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges'.[2]

Our overall conclusion is that whilst increases in capex and opex allowances have been a key driver of recent increases in network charges across many NSPs, the increase in the allowed WACC has generally been more significant. The underlying reasons for the required increases in capex and opex vary across businesses and include factors such as increasing peak demand, replacement of aging assets and meeting environmental, safety and statutory obligations. Furthermore, both the increases in capex and opex allowances and the increase in the WACC have been driven by changes in external circumstances, which have been examined and acknowledged by the AER, rather than being a product of the Rules.

Methodology

This analysis addresses the impact of increases in the revenue requirements on network prices. It does not seek to address the impacts of forecast changes in customer total demand on network prices.

We have used the Post-Tax Revenue Model (PTRM) for each NSP to estimate the P_0 change that would have resulted if the AER's decision at its last determination had adopted:

1. the WACC allowed in the previous regulatory decision; or
2. the real forecast capital expenditure (capex) allowed in the previous regulatory decision; or
3. the real forecast operating expenditure (opex) allowed in the previous regulatory decision.

[1] NERA Economic Consulting, *Capital and Operating Expenditure – Response to AEMC Directions Paper,* April 2012.

[2] AEMC, Directions Paper, p. 28.

For each NSP we have carried out three separate analyses, to identify the impact of each of the above three factors on the P_0 change.[3] We have also identified the residual change in P_0 due to 'other factors'.

Impact of the WACC in driving P_0 increases

The increase in the allowed WACC between regulatory periods has contributed significantly to the observed network price rise in almost all of the jurisdictions analysed. Only for the ACT was the change in the WACC found to have a minor impact on the overall change in real prices.

The increase in WACC is also significant in terms of the materiality of its impact on the overall increase in P_0. For example, in Queensland the change in WACC results in an 18% increase in P_0 for DNSPs (on a weighted average basis), out of the total 45% P_0 change. Similarly, in NSW the change in WACC results in an 12.8% increase in P_0 for DNSPs (on a weighted average basis), out of the total 49.3% P_0 change, whilst in South Australia the change in WACC accounts for a 14.1% increase in P_0 for ElectraNet, out of the total 33.9% P_0 change.

Our analysis of the key drivers of the increase in the WACC between regulatory periods has shown that the increase has been driven by an increase in the debt risk premium. The increase in the debt risk premium has been due to a change in market conditions (predominantly the impact of the global financial crisis), rather than a change in the benchmark credit ratings adopted. The increase in the WACC does not therefore reflect shortcomings in the regulatory framework.

Impact of increased capex allowance in driving network price increases

The increase in the capex allowance between periods has contributed significantly to the observed price rise in all jurisdictions analysed. Specifically, the increase in allowed capex between periods is found to represent at least 18% of the overall change in P_0 for all jurisdictions.

The impact of the increase in allowed capex is the most material in NSW and South Australia. The increase in forecast capex allowances in NSW results in a 16% and 14% increase in P_0 for DNSPs and TNSPs, respectively. In South Australia, the increase in capex allowance implies an increase of 10.6% in the P_0 for ETSA Utilities. Further, our analysis has found that changes in real costs are not a key driver of increases in capex allowances and have in fact had an offsetting impact, ie, the real cost of capex has gone down between this regulatory period and the last.

Our assessment indicates that the key drivers of the increase in capex allowances between regulatory periods differ across NSPs. However augmentation to meet peak demand growth, asset renewal/replacement and environmental, safety & statutory obligations (excluding

[3] The P_0 represents the change in real network prices, where the regulatory control mechanism for the NSP is a price cap, which is the case for most DNSPs. In the case of TNSPs, who are all subject to a revenue cap, and for those DNSPs subject to a revenue cap, the P_0 represents the increase in real revenue.

reliability) are categories of expenditure that have contributed substantively to the overall increase in capex allowance for a large number of DNSPs and TNSPs.

Moreover, our analysis indicates that in reviewing the proposed capex allowances, the AER and the engineering consultants it has commissioned, have recognised these external circumstances as being legitimate drivers of the allowed expenditure and the expenditure allowed as prudent and efficient.

Impact of increased opex allowance in driving P_0 increases

The increase in the allowed opex between periods has contributed significantly to the observed price rise in almost all jurisdictions analysed. Specifically, only for ElectraNet (South Australia) and SP AusNet transmission (Victoria) is the increase in opex allowance found to represent less than 10% of the overall change in P_0.

The impact of the increase in allowed opex is the most material for the DNSPs in NSW, South Australia and the ACT as well as for the TNSP in Tasmania. The increase in forecast opex allowance in the ACT results in an 18% increase in P_0 for ActewAGL. For the NSW DNSPs the increase in P_0 due to the higher opex allowance is 15.6% (on a weighted average basis), whilst for ETSA Utilities the increase is 10%. In Tasmania, Transend's increase in P_0 due to the increase in opex allowance alone would have been 10.6%.

Our assessment of the key drivers of the increase in opex allowances between regulatory periods has identified that real cost escalation has only contributed modestly to the increase in total opex (between 1.9% and 3.5% across all NSPs). In terms of other drivers, the increase in opex allowances reflects circumstances (eg, increased legislative obligations (including Feed-in Tariffs) and expansion of the capital base) which have been recognized as legitimate drivers of expenditure by the AER, and which have been reviewed by external consultants. Moreover, for four out of the five NSPs we reviewed in detail, the reduction made by the AER to the forecast opex exceeded that recommended by the independent consultants.

Impact of 'other' factors in driving P_0 increases

The contribution of other factors on the change in P_0 is less than the combined contribution of the changes in WACC, capex and opex. However the impact of other factors does remain a substantive component of the overall change in the P_0 for all jurisdictions, with the exception of the ACT. For the Victorian DNSPs, and for NSW transmission, changes in these other factors offset some of the impact of WACC, capex and opex, resulting in P_0 changes being below the level that they would otherwise have been.

The impact of other factors is the most material for the Queensland DNSPs and ElectraNet. Specifically, the impact of other factors in Queensland has resulted in a 15% increase in the P_0 for DNSPs (on a weighted average basis). For ElectraNet, the impact of other factors increased the P_0 by 10.3%.

The 'other factors' affecting the P_0 outcomes include increases in actual outturn capital expenditure in the previous regulatory period (rather than the capex allowance for future periods); revenue associated with the operation of the EBSS and differences between outturn and expected demand. Importantly, these factors reflect the legitimate outworkings of the regulatory arrangements, rather than shortcomings in particular regulatory rules.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) for the Energy Networks Association (ENA).

The primary focus of the analysis set out in this report is on analysing the extent to which network price changes for both electricity transmission and distribution businesses in the current regulatory period have been the result of changes in the revenue requirements for NSPs arising from changes in the Weighted Average Cost of Capital (WACC) allowed by the Australian Energy Regulator (AER), increases in forecast capital expenditure allowances and increases in forecast operating expenditure allowances. We have examined the key drivers behind the increases in each of these three factors, to identify the extent that these reflect changes in circumstances recognised as legitimate by the AER or whether they indicate shortcomings with the current regulatory framework.

Specifically, this report is responding to the Australian Energy Market Commission (AEMC's) call in its Directions Paper in relation to the AER's Rule change proposal for further evidence 'on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges'.[4] Our conclusion is that whilst increases in capex and opex allowances have been a key driver of recent increases in network charges across many NSPs, the increase in the allowed WACC has generally been more significant. Furthermore, both the increases in capex and opex allowances and the increase in the WACC have been driven by changes in external circumstances, which have been examined and acknowledged by the AER, rather than being a product of the Rules.

We note that NERA has prepared a separate report for the ENA covering the policy intent of the Chapter 6A Rules, and whether the AER's determinations under Chapter 6A are consistent with that policy intent.[5]

The remainder of this report is structured as follows:

- Section 2 summarises our approach to assessing the extent of the change in network prices/revenues arising as a result of changes in WACC, allowed capex and allowed opex.
- Section 3 sets out our findings in relation to the relative importance of each of these three factors in contributing to the overall increase in network prices/revenues, for each of the five National Electricity Market (NEM) jurisdictions, together with the extent of the change in network prices/revenues which is applicable to other factors. The results of this analysis for each individual network service provider (NSP) are set out in Appendix A.
- Section 4 then analyses the key factors underpinning the increase in the WACC in the current regulatory period for each NSP, and concludes that these factors reflect changes in market conditions, rather than shortcomings with the current Rules.
- Section 5 analysis the key drivers for the increase in capex allowances in the current regulatory period, particularly for those NSPs where the increase in capex allowance has

[4] AEMC, Directions Paper, p. 28.

[5] NERA Economic Consulting, *Capital and Operating Expenditure – Response to AEMC Directions Paper,* April 2012.

been a key driver of an overall substantive increase in their P_0. In each case we review what the NSP said in relation to these drivers in its regulatory submission to the AER, and the AER's responding determination.

- Section 6 presents the complementary analysis of the key drivers of the increase in opex allowances, for those NSPs where the increase in opex allowance has been a key driver of an overall substantial increase in network prices/revenues.

2. Methodology

This section sets out the approach we have adopted in calculating for each NSP the extent to which the change in real network prices/revenues in the current regulatory period has been the result of changes in WACC, capex and opex allowances.

2.1. P_0 Analysis

We have used the post-tax revenue model (PTRM) for each NSP to estimate the P_0 change that would have resulted if the AER's decision at its last determination had adopted:

1. the WACC allowed in the previous regulatory decision; or
2. the real forecast capital expenditure (capex) allowed in the previous regulatory decision;[6] or
3. the real forecast operating expenditure (opex) allowed in the previous regulatory decision.[7]

For each NSP we have carried out three separate analyses, to identify the impact of each of the above three factors on the P_0 change. The P_0 represents the change in real network prices, where the regulatory control mechanism for the NSP is a price cap, which is the case for most DNSPs.[8] In the case of TNSPs, who are all subject to a revenue cap, and for those DNSPs subject to a revenue cap, the P_0 represents the increase in real revenue.

We note that our analysis has considered the impact on P_0 of each factor in isolation, keeping the other two factors constant. As a consequence, the results of our analysis are not additive, and cannot be combined in order to determine the per cent contribution to the P_0 change made by each of the change in WACC, forecast capex and forecast opex. We consider this to be the most appropriate approach, as the identified contribution of each factor in an additive approach will depend upon the order in which the factors are considered. For example, the contribution of an increase in the WACC on the P_0 change will appear greater if the analysis first takes into account the increase in capex forecast, and then applies the increase in WACC to that higher forecast. Approaches which attempt to breakdown the overall P_0 into the contribution of each of the relevant factors therefore risk being misleading.[9]

6 We note that where a previous regulator's decision did not provide an allowed capex profile (either in terms of expenditure type or timing) then we have assumed the same expenditure profile as in the current decision.

7 We note that where a previous regulator's decision did not provide an allowed opex profile (in terms of timing) then we have assumed the same expenditure profile as in the current decision.

8 The exceptions are the Queensland DNSPs, ie ENERGEX and Ergon, which are subject to a revenue cap.

9 For example, the AER's analysis in Table 18.11 on p.817 of its Victorian DNSP final decision 'per cent contribution to 'P_0' is potentially misleading, as the relative per cent contribution of each factor depends on the order in which the factors have been considered in the analysis – see: AER, (2010), *Victorian Electricity Distribution Network Service Providers Distribution Determination 2011–2015*, Final Decision, October 2010, p. 817.

We have also calculated the residual impact of 'other factors' on the P_0 outcomes, over and above the combined impact of the change in WACC, capex forecasts and opex forecasts.[10] 'Other factors' encompass a variety of things, including the realignment of tariff revenue to costs in the final year of the previous regulatory period arising from:

- forecast smoothed revenue for the previous period differing from forecast building block costs;
- forecast operating costs for the previous period differing from actual operating costs;
- forecast capital expenditure for the previous period differing from actual capex; and
- for those NSPs subject to price cap regulation, differences between forecast and actual demand in the final year of the previous regulatory period.

'Other factors' affecting P_0 outcomes also include revenues associated with the operation of the Efficiency Benefit Sharing Schemes (EBSS) and other incentive schemes.

We have used the PTRM models as adopted by the AER in its Final Decision for each NSP (subject to these reflecting the outcome of any subsequent appeal to the Australian Competition Tribunal (Tribunal)), with the exception that for ElectraNet we have used the more recent PTRM model which incorporates the outcome of AER approval of contingent projects. We also note that for the Victorian NSPs the PTRM models used in our analysis do not reflect the outcome of the most recent Tribunal decision.

We have conducted this analysis for each of the distribution network service providers (DNSPs) and transmission network service providers (TNSPs) in the NEM, with the exception of Powerlink and Aurora, where the AER has yet to make a Final Determination.

2.2. Recalculation of the P_0 for each NSP

To quantify the effect of the above three variables on P_0, we have first recalculated the P_0 for each NSP on the basis of setting the X-factor in years 2 to 5 to zero (ie, prices are held constant in real terms after the first year). We have then calculated the P_0 that equalises the building block revenue requirements allowed in the AER's Final Decision[11] with the smoothed forecast revenue.

We have undertaken this recalculation of the P_0 for each NSP in order to be able to isolate the total network price/revenue change implied by the AER's determination into a single P_0 figure.[12] Note that the DNSPs are generally subject to a price cap and so the P_0 represents the change in real network prices from the end of the previous regulatory period to the first year of the current regulatory control period.[13] This approach makes the calculation of the

[10] We note that our analysis considers the combined impact of the increase in WACC, capex and opex forecasts, and then identifies the residual as being due to 'other factors'. Alternative approaches which first adjust for 'other factors' would result in different contributions being calculated for WACC, capex and opex.

[11] Or as amended by the later AER approval of a contingent project (in the case of ElectraNet) or the outcome of an appeal to the Tribunal.

[12] We note that this approach in recalculating P_0 accords with that adopted by the AER in its analysis of the 'per cent contribution to 'P_0' in Table 18.11 of the AER's Victorian DNSP final decision (p.817).

[13] The exceptions are the Queensland DNSPs (ie, Ergon and ENERGEX) which are currently regulated under a revenue cap.

contribution of the different factors to the P_0 change more straightforward, and allows for a clearer comparison of the results across NSPs.

The P_0 for each NSP for the current regulatory period resulting from this recalculation is set out in the following tables. In all cases, a negative P_0 represents an *increase* in network prices/revenues for that NSP.

Table 2.1
Recalculated P_0 - DNSPs

Business	Recalculated P_0
Ausgrid	-58.3%
Essential Energy	-49.7%
Ergon Energy	-47.5%
ENERGEX	-42.6%
ETSA Utilities	-36.4%
Endeavour Energy	-32.9%
ActewAGL	-22.7%
SP AusNet	-19.2%
Jemena	-11.0%
Powercor	-6.3%
United Energy	-5.6%
CitiPower	-1.4%

Source: NERA analysis.

Table 2.2
Recalculated P_0 - TNSPs

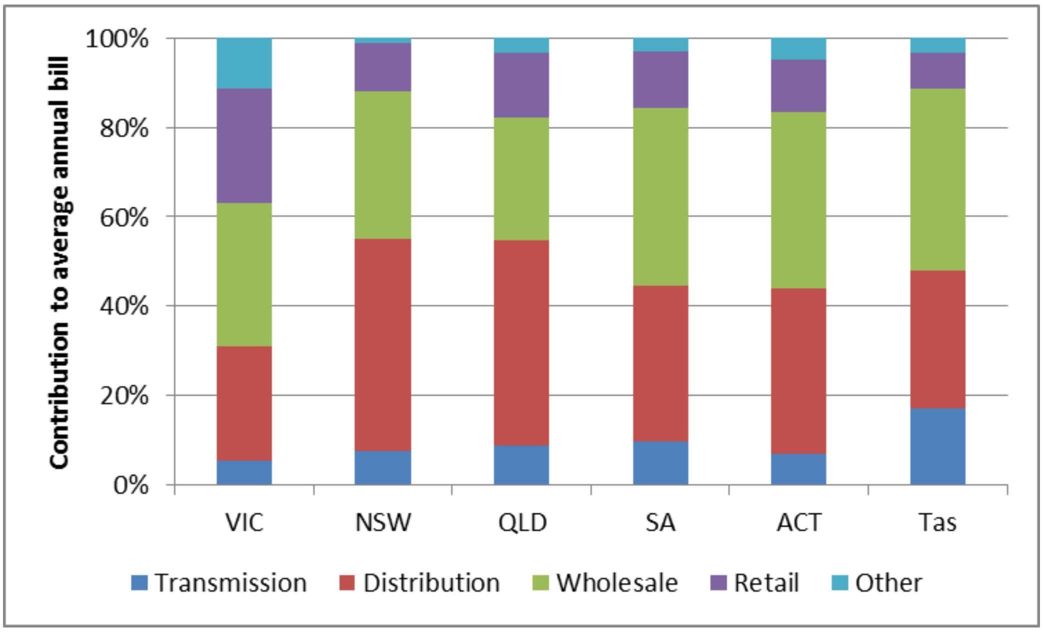
Business	Recalculated P_0
Ausgrid	-46.8%
ElectraNet	-33.9%
Transend	-32.5%
TransGrid	-18.2%
SP AusNet	-15.3%

Source: NERA analysis.

The above tables highlight that there have been some substantial real increases in network prices/revenues in the most recent round of regulatory determinations, with the recalculated P_0 for the DNSPs in NSW, the ACT, Queensland and South Australia reflecting increases in charges of over 20%. Similarly, in NSW (Ausgrid), South Australia and Tasmania, real increases in allowed transmission revenues have also exceeded 20%.

The analysis in this report is focused on the drivers behind the recent increase in network charges, rather than the increase in electricity prices faced by final consumers. Final consumer prices also include wholesale and retail costs, as well as other charges. The relative contribution of transmission and distribution network charges to end-use customer prices varies by jurisdiction, and is summarised in Figure 2.1.

Figure 2.1
Breakdown of Components of End-use Customer Prices, 2010/11



Source: NERA analysis using data in: AEMC, (2011), Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014, Final Report, 25 November 2011.

3. Key Drivers of Network Price Changes

This section sets out the results of our analysis of P_0 changes, comparing the impact of changes in WACC, capex allowances and opex allowances on the overall P_0 change, as well as highlighting the residual change in network prices/revenues due to other factors.

3.1. Impact on P_0 of the increase in WACC

3.1.1. Assumptions

We have calculated the change in P_0 for each NSP if the WACC parameters adopted by the AER in its most recent decision were instead substituted with the WACC parameters adopted in the previous regulatory determination (either by the ACCC (in the case of the TNSPs) or by each of the respective jurisdictional regulators (in the case of the DNSPs)).

Table 3.1 sets out the post-tax nominal WACC and gamma implied by the parameters adopted for the previous regulatory decision and the parameters adopted by the AER in the current decision.[14] Table 3.2 provides the equivalent summary for the TNSPs. Figures for each individual NSP are provided in Appendix B.

Table 3.1
Implied Change in WACC and Gamma - DNSPs

	Implied WACC from Previous Decision	WACC# from Current Decision
NSW – WACC	8.52%	10.07%
(Gamma)	(0.5)	(0.5)
VIC – WACC	8.61%	9.45% - 10.01%
(Gamma)	(0.5)	(0.5)
QLD – WACC	8.50%	9.77%
(Gamma)	(0.5)	(0.25)
SA – WACC	8.94%	9.81%
(Gamma)	(0.5)	(0.25)
ACT – WACC	8.53%	8.84%
(Gamma)	(0.5)	(0.5)

Source: NERA analysis.
 # Includes the allowance for debt raising costs.

14 Note that we have included debt raising costs in the presentation of the WACC for the current regulatory decisions, for comparability with the previous decisions.

Table 3.2
Implied Change in WACC and Gamma - TNSPs

	Implied WACC from Previous Decision	WACC# from Current Decision
NSW – WACC	8.92%	10.07% - 10.10%
(Gamma)	(0.5)	(0.5)
VIC – WACC	8.24%	9.76%
(Gamma)	(0.5)	(0.5)
Tasmania – WACC	8.80%	10.06%
(Gamma)	(0.5)	(0.5)
SA – WACC	8.30%	10.70%
(Gamma)	(0.5)	(0.65)

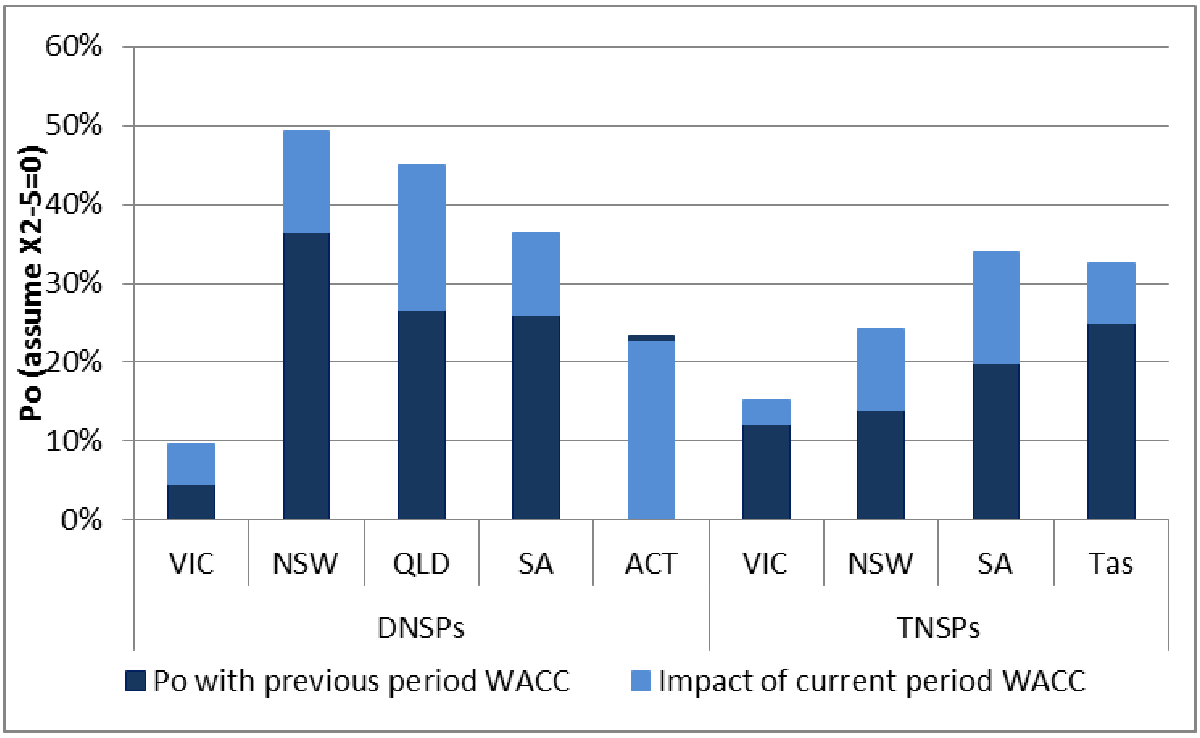
Source: NERA analysis.
 # Includes the allowance for debt raising costs.

3.1.2. Results

Figure 3.1 summarises the significance of the change in the WACC in terms of the increase in the P_0 in each jurisdiction. For each jurisdiction, the height of the light bar represents the total recalculated P_0 (ie, the values set out in the earlier Table 3.1 and Table 3.2),[15] whilst the height of the dark bar represents what the P_0 would have been had the previous WACC been retained. Appendix A provides the breakdown for each of the individual NSPs.

[15] For jurisdictions with more than one DNSP, the P_0 change shown represents the weighted average across all the DNSPs in that jurisdiction (weighted on the basis of the NPV of their respective total revenues).

Figure 3.1
Significance of the Increase in WACC in Driving P_0 Increases



Source: NERA analysis.

It is clear from Figure 3.1 that the increase in the allowed WACC between regulatory periods has contributed significantly to the observed P_0 rise in almost all of the jurisdictions analysed. Only for the ACT was the change in the WACC found to have a minor impact on the overall change in P_0 (and, indeed, to act to *reduce* the overall P_0).

The increase in WACC is also significant in terms of the materiality of its impact on the overall P_0 increases. For example, in Queensland the change in WACC results in an 18% increase in P_0 for DNSPs (on a weighted average basis), ie, an increase from 27% to 45%. Similarly, in NSW the change in WACC results in an 12.8% increase in P_0 for DNSPs (on a weighted average basis), ie, an increase from 36% to 49%, whilst in South Australia the change in WACC accounts for a 14.1% increase in P_0 for ElectraNet, ie, an increase from 20% to 34%.

In section 4 we discuss the key drivers of the increase in the WACC between regulatory periods. Our conclusion in that section is that the increase in WACC has been driven by a change in market circumstances (specifically an increase in the measure of the debt risk premium), and does not reflect any shortcomings in the regulatory framework.

3.2. Impact on P_0 of the increase in capex allowances

3.2.1. Assumptions

We have calculated the change in P_0 for each NSP that would have resulted if the capital expenditure allowed by the AER for the current regulatory period were instead set to the same level (in real terms) as that allowed in each NSP's previous regulatory determination.

The tables below set out the total real forecast capex allowance by jurisdiction in the current and previous regulatory periods, for both DNSPs and TNSPs. In each case the values shown are in real terms, expressed in the dollars at the start of the current regulatory period for each NSP. Appendix B provides the details of the change in capex allowance for each NSP.

Table 3.3
Change in Real Capex Allowance – DNSPs ($m, real)

	Capex Allowance in Previous Period	Capex Allowance in Current Regulatory Period	% Increase
NSW	$5,122.2	$13,035.1	154%
VIC	$3,655.7	$4,702.7	29%
QLD	$7,380.0	$10,801.8	46%
SA	$844.4	$1,579.6	87%
ACT	$123.1	$275.4	124%

Source: NERA analysis using PTRMs provided by NSPs and forecast capex allowances publically available in the various regulatory decisions.

Table 3.4
Change in Real Capex Allowance - TNSPs ($m, real)

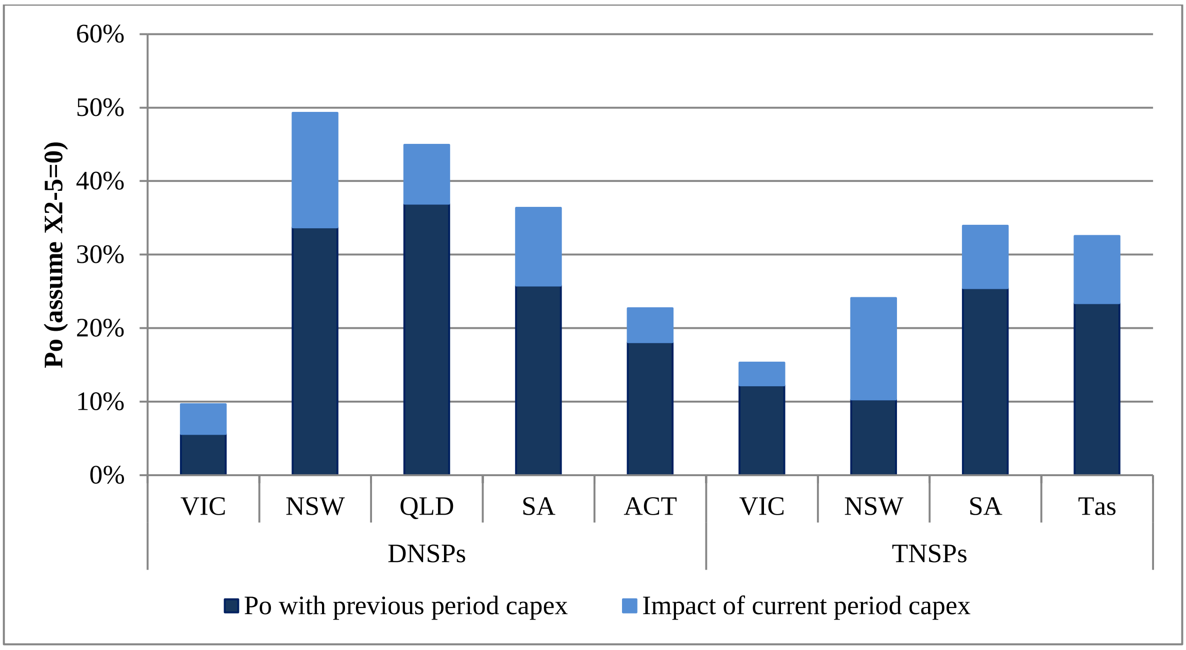
	Capex Allowance in Previous Period	Capex Allowance in Current Regulatory Period	% Increase
NSW	$1,646.7	$3,629.5	120%
VIC	$467.1	$769.6	65%
SA	$411.3	$788.9	92%
Tas	$338.1	$606.4	79%

Source: NERA analysis using PTRMs provided by NSPs and forecast capex allowances publically available in the various regulatory decisions.

3.2.2. Results

Figure 3.2 summarises the significance of the increase in forecast capex allowances in terms of the increase in the P_0 in each jurisdiction. Again, for each jurisdiction the height of the light bar represents the total recalculated P_0,[16] whilst the height of the dark bar represents what the P_0 would have been had the previous capex allowance been retained. Appendix A provides the breakdown for each of the individual NSPs.

Figure 3.2
Significance of Increase in Capex Forecast in Driving P_0 Increases



Source: NERA analysis.

The increase in the capex allowance between periods has contributed significantly to the observed P_0 rise in all jurisdictions analysed. Specifically, the increase in allowed capex between periods is found to be a significant factor and contributes at least 18% of the overall change in the P_0 for all jurisdictions.

The impact on P_0 of the increase in allowed capex is the most material in NSW and South Australia. The increase in forecast capex allowances in NSW results in a 16% and 14% increase in P_0 for DNSPs and TNSPs respectively (on a weighted average basis), ie, an increase from 34% to 49% for DNSPs and an increase from 10% to 24% for TNSPs. In South Australia, the increase in capex allowance implies an increase of 10.6% in the P_0 for the DNSP (ETSA Utilities), ie, an increase from 26% to 36%.

In section 5 we discuss the key drivers of the increase in capex allowances between regulatory periods. Our conclusion in that section is that the increases in capital expenditure allowances reflect circumstances (eg, increases in peak demand; asset condition) which have been recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime.

[16] For jurisdictions with more than one DNSP, the P_0 change shown represents the weighted average across all the DNSPs in that jurisdiction (weighted on the basis of the NPV of their respective total revenues).

3.3. Impact on P_0 of the increase in opex allowances

3.3.1. Assumptions

We have calculated the change in P_0 for each NSP that would have resulted if the operating expenditure allowed by the AER for the current regulatory period were instead set to the same level (in real terms) as that allowed in each NSP's previous regulatory determination.

The tables below set out the total real forecast opex allowance by jurisdiction in the current and previous regulatory periods, for both DNSPs and TNSPs. In each case the values shown are in real terms, expressed in the dollars at the start of the current regulatory period for each NSP. Appendix B provides the details of the change in opex allowance for each NSP.

Table 3.5
Change in Real Opex Allowance – DNSPs ($m, real)

	Opex Allowance in Previous Period	Opex Allowance in Current Regulatory Period	% Increase
NSW	$4,191.3	$5,982.3	43%
VIC	$2,420.1	$2,700.0	12%
QLD	$2,943.9	$3,400.0	15%
SA	$762.4	$1,024.6	34%
ACT	$228.3	$339.6	49%

Source: NERA analysis using PTRMs provided by NSPs and forecast opex allowances publically available in the various regulatory decisions.

Table 3.6
Change in Real Opex Allowance – TNSPs ($m, real)

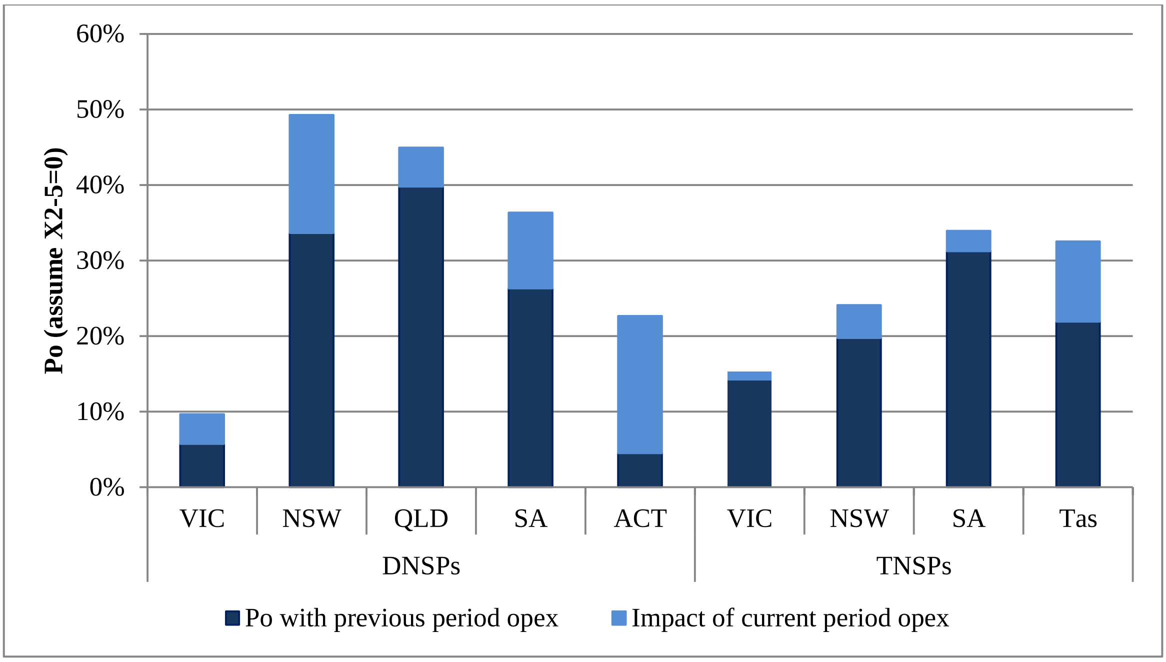
	Opex Allowance in Previous Period	Opex Allowance in Current Regulatory Period	% Increase
NSW	$824.4	$986.5	20%
VIC	$972.8	$1,003.5	3%
SA	$284.6	$310.2	9%
Tas	$176.8	$254.3	44%

Source: NERA analysis using PTRMs provided by NSPs and forecast opex allowances publically available in the various regulatory decisions.

3.3.2. Results

Figure 3.3 summarises the significance of the increase in forecast opex allowances in terms of the increase in the P_0 in each jurisdiction. Again, for each jurisdiction the height of the light bar represents the total recalculated P_0, whilst the height of the dark bar represents what the P_0 would have been had the previous opex allowance been retained. Appendix A provides the breakdown for each of the individual NSPs.

Figure 3.3
Significance of Increase in Opex Forecast in Driving P_0 Increases



Source: NERA analysis.

The increase in the allowed opex between periods has contributed significantly to the observed P_0 rise in almost all jurisdictions analysed. Specifically, only for ElectraNet (South Australia) and SP AusNet transmission (Victoria) is the increase in opex allowance found to represent less than 10% of the overall change in the P_0.

The impact of the increase in allowed opex is the most material for the DNSPs in NSW, South Australia and the ACT as well as for the TNSP in Tasmania. The increase in forecast opex allowance in the ACT results in an 18% increase in P_0 for ActewAGL, ie, an increase from 4% to 23%. For the NSW DNSPs the increase in P_0 due to the higher opex allowance is 15.6% (on a weighted average basis), ie, an increase from 34% to 49%, whilst for ETSA Utilities the increase is 10%, ie, an increase from 26% to 36%. In Tasmania, Transend's increase in P_0 due to the increase in opex allowance alone would have been 10.6%, ie, an increase from 22% to 33%.

In section 6 we discuss the key drivers of the increase in opex allowances between regulatory periods. Our conclusion in that section is that real cost escalation has only contributed modestly to the increase in total opex (ie, between 1.9% and 3.5% across all NSPs). In terms of other drivers, the increase in opex allowances reflects circumstances (eg, increased legislative obligations (including Feed-in Tariffs) and expansion of the NSP's capital base) which have been recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime.

3.4. Contribution of other factors to P_0 increases

3.4.1. Assumptions

The above analysis has focused on the impact of each of the increase in WACC, capex allowances and opex allowances on the P_0 increases for NSPs across the NEM. As discussed earlier, we have considered each of these factors in isolation.

We have also considered to what extent the P_0 increases have been driven by factors other than the change in WACC and expenditure allowances.

Specifically, we have calculated the change in P_0 for each NSP retaining the WACC, capex and opex allowed in the previous regulatory decision, in order to assess what effect *other factors* (ie, besides changes in allowed WACC, capex and opex) have had on the increase in the P_0.

3.4.2. Results

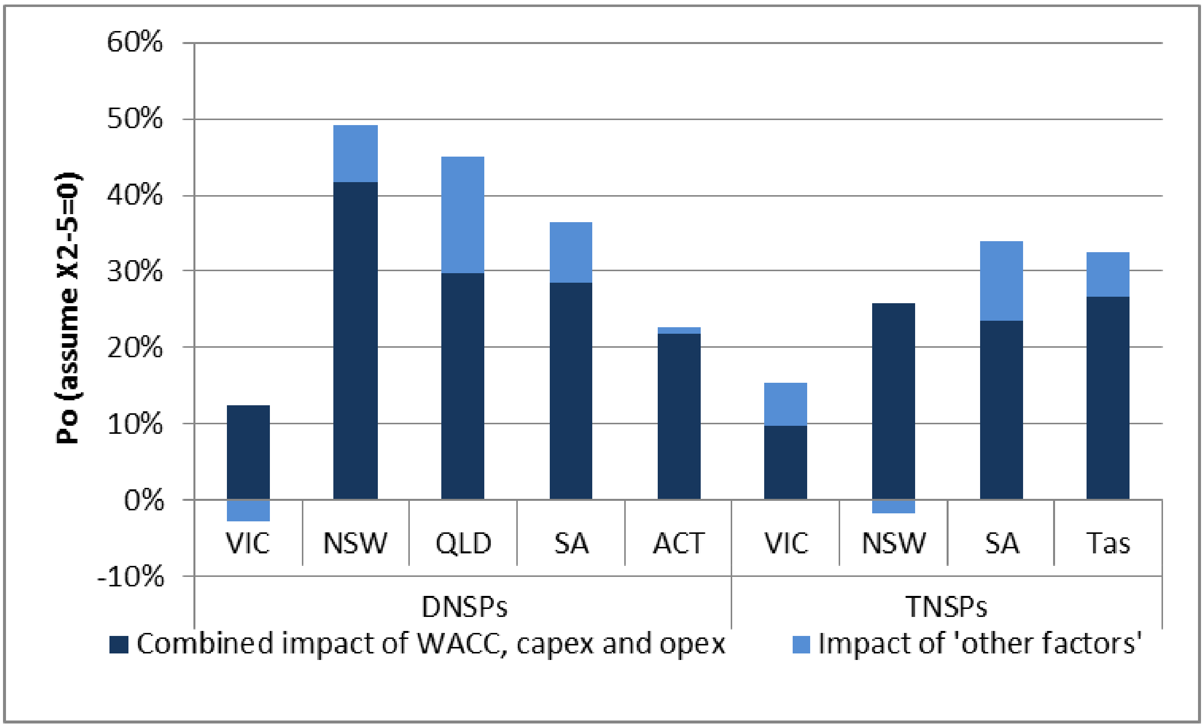
Figure 3.4 summarises the significance of other factors in terms of the increase in network prices/revenues in each jurisdiction. For each jurisdiction the height of the light bar represents the total recalculated P_0, whilst the dark portion of the bar represents the combined impact of the increases in the allowed WACC, capex and opex. Appendix A provides the breakdown for each of the individual NSPs.

Figure 3.4 shows that the contribution of other factors on the change in P_0 is less than the combined contribution of the changes in WACC, capex and opex. However the impact of other factors does remain a substantive component of the overall change in the P_0 for all jurisdictions, with the exception of the ACT.

In Victoria distribution and NSW transmission, changes in these other factors offset some of the impact of WACC, capex and opex, resulting in P_0 changes being below the level that they would otherwise have been.

The impact of other factors is the most material for the Queensland DNSPs and ElectraNet (South Australia). The impact of other factors in Queensland has resulted in a 15% increase in the P_0 for DNSPs (on a weighted average basis), ie, an increase from 30% to 45%. For ElectraNet, the impact of other factors increased the P_0 by 10.3%, ie, an increase from 24% to 34%.

Figure 3.4
Significance of Other Factors in Driving P_0 Increases



Source: NERA analysis.

The 'other factors' affecting the P_0 outcomes encompass a variety of things, including the realignment of tariff revenue to costs in the final year of the previous regulatory period arising from:

- forecast smoothed revenue for the previous period differing from forecast building block costs;
- forecast operating costs for the previous period differing from actual operating costs;
- forecast capital expenditure for the previous period differing from actual capex; and
- for those NSPs subject to price cap regulation, differences between forecast and actual demand in the final year of the previous regulatory period.

P_0 outcomes will also be affected by revenues associated with the operation of the Efficiency Benefit Sharing Schemes (EBSS) and other incentive schemes.

Importantly, these factors reflect the legitimate outworkings of the regulatory modelling, rather than any shortcomings in particular regulatory rules.

As part of the information gathering component of this assignment, we asked those NSPs for whom the impact of 'other factors' has a substantial impact on P_0 changes for information on the key components of these 'other factors'.

ENERGEX advised us that the following 'other' factors help explain its P_0 increase in the current regulatory period (noting that the first two are likely to account for the majority of the gap):

- In the previous regulatory control period (ie, 2004/5-2009/10), ENERGEX spent above its capex allowance, primarily to address compliance with obligations arising from the Queensland Government's Electricity Distribution Service Delivery (EDSD) review and to meet demand growth on its network. This contributed to a higher starting Regulatory Asset Base (RAB) for the current regulatory period;
- The tax allowance component under the Queensland Competition Authority's building block approach was based on actual tax paid, which is substantially lower than the assumed benchmark tax costs adopted by the AER; and
- In the previous regulatory control period (2005-06 to 2009-10), ENERGEX's revenue was reduced to account for over-recoveries, adjustments to asset lives and opex carry forward from the 2001-02 to 2004-05 control period. These adjustments totalled $234 million and understate the efficient costs in the previous regulatory control period. In addition, the 2009-10 revenue included a downward adjustment of approximately $20.4 million for over recovery in 2007-08 which further understates the starting revenue and overstates the P_0

Ergon Energy advised us that the following 'other' factors help explain its P_0 increase between periods:[17]

- In the 2005-10 regulatory control period, Ergon Energy spent above its capex allowance, primarily to address customer and demand growth on its network. This contributed to a higher starting RAB for the current regulatory period;
- The tax allowance component under the Queensland Competition Authority's building block approach was based on actual tax paid, which is substantially lower than the assumed benchmark tax costs adopted by the AER;
- There was a carry forward amount from the previous period of $10.7 million ($2009-10) for accelerated depreciation due to Cyclone Larry, which further increased the allowed revenue in the first year of the current period; and
- The starting point of the 2009-10 revenue included a net over-recovery adjustment of approximately $9.3 million for revenue over recovery, cost pass through for Cyclone Larry and exclusion of excluded distribution services revenue, which would understate the starting revenue and overstate the overall P_0.

ElectraNet advised us that the following 'other' factors help explain its P_0 increase between this period and the last:[18]

- $21 million extra for capitalised equity raising costs - equity raising costs in the previous regulatory period were provided for by the ACCC as an allowance in perpetuity and the AER converted this into an amount capitalised in the RAB as part of the most recent decision;[19]
- $29 million for easement compensation costs;

[17] Similar to ENERGEX, Ergon Energy noted that the first two are likely to account for the majority of the gap.

[18] Note all figures are provided in $2007/08.

[19] AER, (2008), *ElectraNet Transmission Determination 2008–09 to 2012–13*, Final Decision, 11 April 2008, p. ix.

- A further $46.6 million for easement transaction or acquisition costs, granted as a result of merits review; and
- $17 million for readmission of optimised assets.

4. Drivers of the Increase in WACC

From our analysis of the drivers of the change in P_0, it is evident that the increase in the WACC between regulatory periods is a material driver of the change in real network prices/revenues.

We have undertaken further analysis to identify the key drivers of the increase in the WACC.

4.1. Methodology

The current return on assets for all NSPs is set by reference a nominal 'vanilla' post-tax WACC which is defined by the following formula:[20]

$$WACC = k_e \frac{E}{D+E} + k_d \frac{D}{D+E}$$

Where:

k_e is the nominal return on equity, determined by a domestic Sharpe-Lintner capital asset model (CAPM), ie:

$$k_e = r_f + \beta_e \times (r_m - r_f)$$

where

r_f is the nominal risk free rate;

β_e is the equity beta; and

$(r_m - r_f)$ is the domestic market risk premium;

k_d is the nominal cost of debt, as observed from observable domestic corporate bond performance, ie:

$$k_d = r_f + DRP$$

DRP is the nominal debt risk premium, ie, the difference between the nominal risk free rate and the yield on the benchmark corporate debt;

$\frac{D}{D+E}$ is the debt to value ratio of a benchmark efficient business; and

$\frac{E}{D+E}$ is the equity to value ratio of a benchmark efficient business.

For TNSPs, previous determinations applied a similar nominal 'vanilla' post-tax WACC. The process of comparing the current and previous allowed WACCs is therefore straight

20 Clauses 6.5.2(b) and 6A.6.2(b) of the NER.

forward. Table 4.2, sets out the WACC applied to TNSPs in the current and immediately preceding determination.[21]

For DNSPs, the comparison is complicated by the fact that previous jurisdictional state regulators determined revenues on the basis of a variety of WACC definitions. For DNSPs in Queensland, South Australia, the ACT and Tasmania, we have used the constituent WACC parameters used in the previous state determinations in order to calculate a nominal 'vanilla' post-tax WACC.

However, in Victoria the Essential Services Commission (ESC) set a real 'vanilla' post-tax WACC and so all WACC parameters were defined in real terms. To estimate a comparable nominal 'vanilla' post-tax WACC, we converted the real parameter values to nominal values, using the Fisher equation and the ESC's forecast of inflation.[22]

The previous rate of return applied to the NSW DNSPs was a real pre-tax WACC of 6.70 per cent.[23] However, in arriving at this point estimate, the Independent Pricing and Regulatory Authority (IPART) assessed a plausible range for some WACC parameters. To back-solve the constituent point estimates of each WACC parameters consistent with IPART's 2004 actual determination of 6.70 per cent, we have generally taken the mid-point of the identified range. The exception to this rule was the equity beta, where we employed the excel solver function to ensure that the real pre-tax WACC matched the point estimate determined by IPART. Table 4.1 sets out the range specified by IPART in its final decision as well as the point estimates assumed by NERA.

Table 4.2 and Table 4.3 below set out the WACC applied to TNSPs and DNSPs in each jurisdiction in the current and immediately preceding determinations.

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21 Note that Powerlink has been excluded because the AER has only recently released its draft determination.

22 The Fisher equation, is specified by the following formula:

$Nom = \frac{1+real}{1+\rho} - 1$ where, ρ is the inflation rate expected by the ESC in its 2005 decision, ie, 2.56%.

23 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09: Final Report*, June 2004, p. 218.

Table 4.1
IPART's 2004 Regulatory WACC Decision

Parameter	IPART specified range Low	IPART specified range High	NERA estimate Point
Nominal risk free rate (06/05/04)	5.90%	5.90%	5.90%
Inflation	2.50%	2.50%	2.50%
Real risk free rate (06/05/04)	3.30%	3.30%	3.30%
Market risk premium	5%	6%	5.50%
Debt margin 0.9%-1.1%	0.90%	1.10%	1.00%
Allowance for debt raising costs	0.125%	0.125%	0.125%
Debt to total assets	60.00%	60.00%	60.00%
Dividend imputation factor (gamma)	50.00%	50.00%	50.00%
Tax rate	30.00%	30.00%	30.00%
Equity beta	0.78	1.11	0.918
Cost of equity (nominal post-tax)	9.80%	12.56%	10.95%
Cost of debt (nominal pre-tax)	6.93%	7.13%	7.03%
WACC (nominal post-tax)	6.14%	7.13%	6.56%
WACC (real pre-tax)	6.11%	7.50%	6.70%

Source: NERA analysis and IPART's 2004 NSW DNSP decision, page 218.

Table 4.2
TNSP Regulatory WACC Decisions

	Ausgrid		ElectraNet		Transend		TransGrid		SP AusNet	
	Previous	Current*	Previous	Current*	Previous	Current*	Previous	Current*	Previous	Current*
Risk free rate	*5.98%*	5.82%	5.17%	6.20%	5.86%	5.80%	*5.98%*	5.86%	6.09%	*5.12%*
Forecast inflation	*2.49%*	2.47%	2.07%	2.63%	2.32%	2.47%	*2.49%*	2.47%	2.59%	*2.04%*
Debt risk premium	*0.90%*	3.08%	1.22%	3.50%	1.02%	3.10%	*0.90%*	3.07%	2.11%	*1.20%*
Equity risk premium (β_e*MRP)	*6.00%*	6.00%	6.00%	6.00%	6.00%	6.00%	*6.00%*	6.00%	6.00%	*6.00%*
Gearing (D/V)	*60.00%*	60.00%	60.00%	60.00%	60.00%	60.00%	*60.00%*	60.00%	60.00%	*60.00%*
Return on debt	6.88%	8.90%	6.39%	9.70%	6.88%	8.89%	6.88%	8.93%	8.20%	6.32%
Return on equity	11.98%	11.82%	11.17%	12.20%	11.86%	11.80%	11.98%	11.86%	12.09%	11.12%
Nominal vanilla post-tax WACC	**8.92%**	**10.07%**	**8.30%**	**10.70%**	**8.87%**	**10.06%**	**8.92%**	**10.10%**	**9.76%**	**8.24%**
Real vanilla post-tax WACC[#]	6.43%	7.59%	6.23%	8.07%	6.55%	7.58%	6.43%	7.62%	7.17%	6.20%
Gamma	*0.5*	0.5	*0.5*	0.65	*0.5*	0.5	*0.5*	0.5	0.5	*0.5*

Source: NERA analysis of the WACC publically available in the various regulatory decisions.
** The current and previous WACC as determined by the AER has been adjusted to incorporate the allowed debt raising costs into the debt risk premium.*
[#] The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

Table 4.3
DNSP Regulatory WACC Decisions

	NSW		Victoria		Queensland		South Australia		ACT	
	Previous	**Current***	**Previous**	**Current***	**Previous**	**Current***	**Previous**	**Current***	**Previous**	**Current***
Risk free rate	5.90%	5.82%	5.27%	5.08%-5.65%	5.61%	5.64%	5.80%	5.89%	5.62%	4.29%
Forecast inflation	2.50%	2.47%	2.64%	2.57%	1.22%	2.52%	2.44%	2.52%	2.17%	2.47%
Debt risk premium	1.00%	3.08%	1.46%	3.80%-4.14%	2.76%	3.42%	1.64%	3.07%	1.25%	3.59%
Equity risk premium (β_e*MRP)	5.05%	6.00%	6.15%	5.20%	5.40%	5.20%	5.40%	5.20%	5.40%	6.00%
Gearing (D/V)	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
Return on debt	6.90%	8.90%	6.73%	8.90%-9.44%	6.83%	9.06%	7.44%	8.96%	6.87%	7.88%
Return on equity	10.95%	11.82%	11.42%	10.28%-10.85%	11.01%	10.84%	11.20%	11.09%	11.02%	10.29%
Nominal vanilla post-tax WACC	**8.52%**	**10.07%**	**8.61%**	**9.45%-10.01%**	**8.50%**	**9.77%**	**8.94%**	**9.81%**	**8.53%**	**8.84%**
Real vanilla post-tax WACC[#]	6.02%	7.60%	5.97%	6.88%-7.43%	5.74%	7.25%	6.50%	7.29%	6.36%	6.37%
Gamma	0.5	0.5	0.5	0.5	0.5	0.25	0.5	0.25	0.5	0.5

Source: NERA analysis of the WACC publically available in the various regulatory decisions.
** The current and previous WACC as determined by the AER has been adjusted to incorporate the allowed debt raising costs into the debt risk premium.*
[#] The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

4.2. Results

The results of the analysis described above are set out in Table 4.6 (for DNSPs) and Table 4.7 (for TNSPs).

It is clear from these tables that the increase in the real WACC between regulatory periods is predominantly due to a higher debt risk premium (DRP). This finding is consistent across all DNSPs and TNSPs.

The Tribunal decision in 2011 to lower the value of gamma to 0.25[24] also has a significant impact on the P_0 calculation for those affected NSPs (ie, ETSA Utilities, ENERGEX and Ergon). However we note that the Queensland DNSPs have not been permitted to pass through the implied change in revenues resulting from the Tribunal decision, and hence the change in gamma is not a driver of the observed real network price change for these NSPs.

4.2.1. Increase in the DRP

Given its importance in driving the increase in the WACC, we have further considered the drivers behind the increase in the DRP between regulatory periods. Importantly, the DRP is affected by both the decision as to the appropriate benchmark to adopt for long term debt, and the observed market value associated with that benchmark.

The AER has adopted a benchmark for Australian corporate debt with a BBB+ credit rating and a 10 year term for maturity in all of its determinations, for both DNSPs and TNSPs. Furthermore, the AER concluded that this was the appropriate benchmark to adopt in its 2009 Statement of Regulatory Intent (SORI),[25] reflecting the evidence available at that time.

The tables below set out the benchmarks adopted in determining the DRP by the relevant regulator at the time of each NSP's previous regulatory determination, ie prior to the determination undertaken by the AER.

24 Application by ENERGEX Limited (Gamma) (No 5) [2011] ACompT 9, 12 May 2011

25 AER (2009), Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution).

Table 4.4
Benchmark Adopted for Determining the DRP - DNSPs

Business	Increase in DRP	Previous benchmark	Current benchmark
Ausgrid	208 basis points	BBB+ to BBB, 10 yr	BBB+, 10 yr
Essential Energy	208 basis points	BBB+ to BBB, 10 yr	BBB+, 10 yr
Ergon Energy	220 basis points	BBB+, 10 yr	BBB+, 10 yr
ENERGEX	220 basis points	BBB+, 10 yr	BBB+, 10 yr
ETSA Utilities	143 basis points	BBB+, 10 yr	BBB+, 10 yr
Endeavour Energy	208 basis points	BBB+ to BBB, 10 yr	BBB+, 10 yr
ActewAGL	234 basis points	BBB+, 10 yr	BBB+, 10 yr
SP AusNet	268 basis points	BBB+, 10 yr	BBB+, 10 yr
Jemena	234 basis points	BBB+, 10 yr	BBB+, 10 yr
Powercor	237 basis points	BBB+, 10 yr	BBB+, 10 yr
United Energy	237 basis points	BBB+, 10 yr	BBB+, 10 yr
CitiPower	237 basis points	BBB+, 10 yr	BBB+, 10 yr

Source: NERA analysis using publically available regulatory decisions.

Table 4.5
Benchmark Adopted for Determining the DRP - TNSPs

Business	Increase in DRP	Previous benchmark	Current benchmark
Ausgrid	218 basis points	A, 10 yr	BBB+, 10 yr
ElectraNet	228 basis points	A, 10 yr	BBB+, 10 yr
Transend	210 basis points	A,5.5 yr	BBB+, 10 yr
TransGrid	217 basis points	A, 10 yr	BBB+, 10 yr
SP AusNet	91 basis points	A, 5 yr	BBB+, 10 yr

Source: NERA analysis using publically available regulatory decisions.

We note that for DNSPs, the benchmark credit rating adopted by the AER in the current regulatory period (ie, BBB+) is the same as, or slightly higher, than the benchmark credit rating adopted by the previous jurisdictional regulators at the time of the earlier regulatory decisions, whilst a 10-year term has been assumed in both cases. This implies that, absent any change in market conditions, the DRP estimated by the AER for the DNSPs in the current period would have been the same as or *below*[26] the DRP estimated in the previous period. The observed increase in the DRP for DNSPs is therefore solely due to changes in market conditions (predominantly the impact of the global financial crisis), leading to increases in the measurement of the DRP, rather than reflecting any change in the provisions in the Rules.

For the TNSPs, the AER benchmark (again, BBB+, 10 year) has changed from that applied in the previous regulatory periods (where a benchmark credit rating of A was adopted for all TNSPs). However the change in the benchmark credit rating was determined by the AER as appropriate in its 2009 SORI. The AER was not subject to any restrictions in its choice of benchmark credit rating in its review. Therefore, again, the change in DRP for the TNSPs, which has driven the increase in the WACC in the current regulatory period and, in turn, has had a substantive impact on real network revenues, does not reflect any shortcomings with the current regulatory arrangements.

4.2.2. Gamma

In 2011, the Tribunal[27] determined that the value of gamma (used to calculate the compensation for tax) should be set to 0.25, rather than 0.65 as determined by the AER.

The Tribunal's decision to lower the value of gamma has had a significant impact on revenues in the current regulatory period:

- ETSA Utilities – increase in tax compensation of \$162.2m (ie, which in itself leads to a P_0 price increase by 5.8%)
- ENERGEX – increase in tax compensation of \$189.5m (ie, which in itself leads to a P_0 revenue increase by 3.7%)
- Ergon – increase in tax compensation of \$131.5m (ie, which in itself leads to a P_0 revenue increase by 2.8%)

We have not incorporated the impact of the Tribunal's decision on the P_0 for the Victorian DNSPs given an updated PTRM is not yet available.

As noted above, Ergon and ENERGEX have not been permitted in practice by their shareholder (the Queensland government) to pass through the implied change in revenue for 2011-12 resulting from the Tribunal decision, and hence the change in gamma is not a driver of the *observed* real network price change for those NSPs.

The Tribunal's decision to lower the value of gamma reflects the outcome of its deliberations, rather than indicating a shortcoming with the regulatory framework.

26 Since where a higher benchmark credit rating has adopted by the AER, this would imply a lower cost of debt, all else equal.

27 Application by ENERGEX Limited (Gamma) (No 5) [2011] ACompT 9, 12 May 2011

Table 4.6 Analysis of the Drivers for the Change in WACC – DNSPs

DNSPs	Victoria					NSW			Queensland		ACT	SA
	Citipower	Powercor	SP AusNet	Jemena	United Energy	Ausgrid	Endeavour	Essential Energy	ENERGEX	Ergon	ActewAGL	ETSA Utilities
Real WACC: Current Decision#	6.88%	6.88%	7.13%	7.43%	6.88%	7.60%	7.60%	7.60%	7.25%	7.25%	6.37%	7.29%
Real WACC: Previous Decision#	5.97%	5.97%	5.97%	5.97%	5.97%	6.02%	6.02%	6.02%	5.74%	5.74%	6.36%	6.50%
Change basis points	91	91	116	146	91	158	158	158	151	151	1	79
Percentage increase in WACC	15.3%	15.3%	19.5%	24.5%	15.3%	26.2%	26.2%	26.2%	26.3%	26.3%	0.1	12.1%
Contribution to change in WACC												
Risk free rate	-19	-19	-13	38	-19	-8	-8	-8	3	3	-133	9
Debt risk premium	142	142	161	140	142	125	125	125	132	132	140	86
Equity premium	-38	-38	-38	-38	-38	38	38	38	-8	-8	24	-8
Inflation	7	7	7	7	7	3	3	3	24	24	-30	-8
Tax (additional Revenue)	0	0	0	0	0	0	0	0	$203m ($P_0$ 3.7%)	$142.9m ($P_0$ 2.8%)	0	$149.4m ($P_0$ 5.8%)

 # The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

Table 4.7 Analysis of the Drivers for the Change in WACC – TNSPs

TNSPs	SP AusNet	TransGrid	Energy Australia	ElectraNet	Transend
Real WACC: Current Decision#	7.17%	7.62%	7.59%	8.07%	7.58%
Real WACC: Previous Decision#	6.20%	6.48%	6.48%	6.23%	6.55%
Change basis points	97	113	109	184	103
Percentage increase in WACC	15.7%	17.4%	16.9%	29.5%	13.6%
Contribution to change in WACC					
Risk free rate	97	-12	-16	103	-6
Debt risk premium	55	125	125	137	131
Equity premium	0	0	0	0	5
Inflation	-55	2	2	-56	-15
Tax (additional Revenue)	0	0	0	-$3.0m	0

The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

5. Drivers of the Increase in Capex Allowances

The analysis in section 3.2 highlights that the increase in capex allowances in the current regulatory period compared to the previous regulatory period has had a substantive impact on the P_0 increases in the current period.

The next stage of our analysis has been to identify the drivers behind the increase in capex allowances. We first assess how much of the increase in the allowances are due to real cost escalation. We then analyse the other key drivers of the increase.

5.1. Real cost escalation

In order to estimate how much of the change in capex allowances is due to real cost escalation, we have used real cost indices commissioned by ENA from Sinclair Knight Merz (SKM). These indices act as a proxy for the real cost escalators adopted by the AER and the previous jurisdictional regulators in their regulatory decisions. Information on the actual real cost escalation factors adopted by the previous jurisdictional regulators is not available from public sources. For the purpose of this exercise, we consider that the escalators developed by SKM are a reasonable proxy for the escalators applied in the regulatory decisions, whilst recognising that the actual escalation factors adopted will have differed somewhat from these values.

The AER is not constrained under the Rules in substituting its own real cost escalation indices. Indeed, we note that the AER has chosen to substitute its own real cost escalators in all of its final determinations for each of the DNSPs and TNSPs.[28] As a consequence, any change in network charges due to the impact of real cost escalation on capex allowances does not indicate a shortcoming in the operation of the Rules.

SKM has modelled the changing price of equipment and project costs through combining forecast movements in the price of input components, with 'weightings' for the relative contribution of each component to final equipment/project costs. Specifically, SKM has undertaken this exercise for a 'typical' transmission and distribution network capex and opex program to derive an overall capex and opex escalator for each sector. The real cost indices developed by SKM are reproduced in Appendix C.

Table 5.1 sets out the percentage change in the real capex allowance between the current and previous regulatory periods accounting for changes in real costs of capex, for each DNSP.

[28] For example, the AER reduced Ausgrid's total forecast distribution capex by $373.3 million ($m, 2008-09) to reflect its own real cost escalators in the final decision (see: AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 144). Similarly, the AER reduced Transend's total forecast transmission capex by $63.1 million ($m, 2008-09) to reflect its own real cost escalators in the final decision (see: AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. 65).

Table 5.1
Change in Capex Allowance Due to Real Cost Escalation - DNSPs

Business	Change in real capex
Ausgrid	-6.3%
Essential Energy	-6.3%
ActewAGL	-6.2%
Endeavour Energy	-6.1%
ENERGEX	-5.3%
Ergon Energy	-5.1%
ETSA Utilities	-5.0%
United Energy	-4.6%
CitiPower	-4.5%
Powercor	-4.4%
SP AusNet	-4.4%
Jemena	-4.0%

Table 5.2 provides the same breakdown for TNSPs.

Table 5.2
Change in Capex Allowance Due to Real Cost Escalation - TNSPs

Business	Change in real capex
Ausgrid	-6.2%
ElectraNet	-4.0%
Transend	-4.5%
TransGrid	-6.1%
SP AusNet	-1.1%

It is evident from the above that changes in real costs have not been a key driver of the increase in the capex allowance for NSPs in the most recent regulatory period. In fact, real costs for capex have *fallen* between the current and previous regulatory periods, implying that real costs have had a negative impact on the increase in the capex allowance (ie, have resulted in capex allowances being lower in real terms than they otherwise would have been).

This result is driven by the fact that the demand for many of the inputs used by NSPs slowed significantly following the onset of the global financial crisis in 2008. Put another way, the previous regulatory period for all businesses coincided (mostly) with times of high prices for the inputs used by DNSPs and TNSPs, while the current regulatory period incorporates much lower observations/expectations regarding prices for inputs.

This is evidenced in the real cost escalators provided by SKM, whereby the real cost of capex for both DNSPs and TNSPs dropped off significantly, following a peak in 2008. Figure 5.1 below illustrates this reduction in the real cost of capex for DNSPs as well as how it coincides with the last two regulatory periods (using the NSW DNSPs as an illustration, however, note that the other DNSPs have regulatory periods that are within one or two years of the NSW DNSPs).

Figure 5.1
SKM's Cumulative Real Cost Escalation of Capex – DNSPs,
(July 2003 = 1.0)

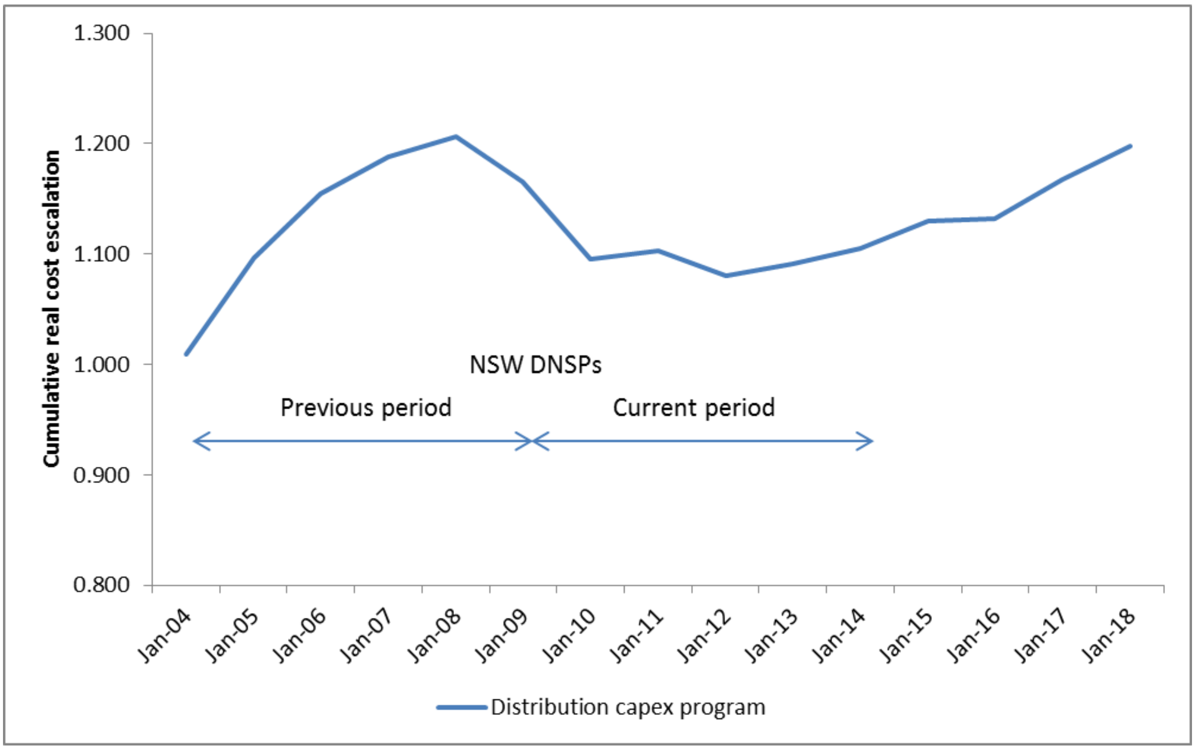
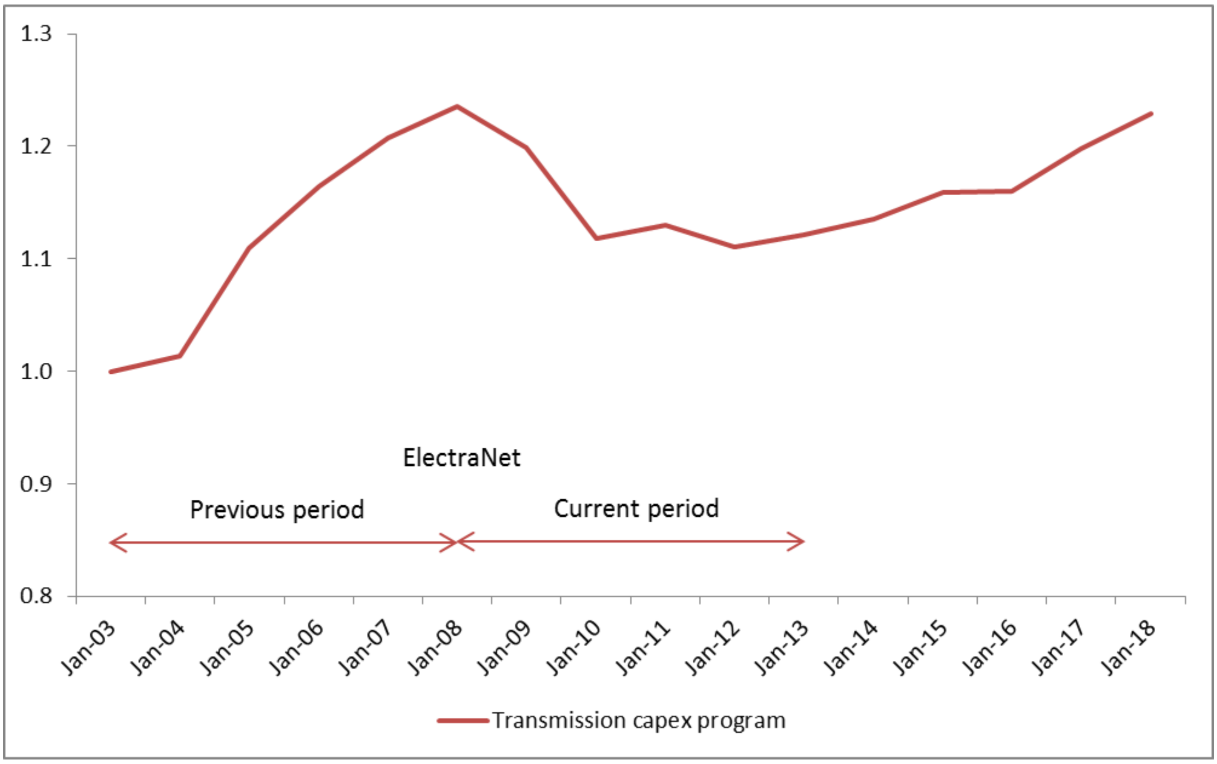


Figure 5.2 illustrates the reduction in the real cost of capex for TNSPs following the global financial crisis estimated by SKM, as well as how it coincides with the last two regulatory periods (using ElectraNet as an illustration, however, note that the other TNSPs have regulatory periods that are within one or two years of ElectraNet's).

Figure 5.2
SKM's Cumulative Real Cost Escalation of Capex – TNSPs,
(July 2003 = 1.0)



5.2. Key drivers of the increase in capex allowances

In order to identify the key drivers of the increase in capex forecasts, NERA has facilitated completion of a survey from all DNSPs and TNSPs in the NEM. As part of this survey, the NSPs were asked to complete a template which included a breakdown of the capex allowance in the current and previous regulatory periods into key component categories.

For both TNSPs and DNSPs the following eight categories of capital expenditure were identified: (i) asset renewal/replacement; (ii) augmentation to meet peak demand growth; (iii) quality, reliability and security of supply enhancement; (iv) new customer connections (excluding customer contributions); (v) environmental, safety and statutory obligations (excluding reliability); (vi) SCADA and network control; (vii) non-network assets; and (viii) other.

Table 5.3 and Table 5.4 identify those categories of capex which have made the greatest contribution (in real $m terms) to the overall increase in the capex allowance for each DNSP and TNSP (respectively). For each NSP we have highlighted those categories of capex that have contributed the most to the increase. Appendix B provides further information in relation to each NSP.

It is evident from the tables that the key drivers of the increase in the capex allowance differ across NSPs. However augmentation to meet peak demand growth, asset renewal/replacement, environmental, safety and statutory obligations and new customer connections are categories of expenditure that have contributed substantively to the overall increase in capex allowance for a large number of DNSPs and TNSPs.

In the case of augmentation to meet peak demand growth, we note that it is increases in peak demand at a particular feeder level which are the key driver of network capex, rather than the system-wide increase in peak demand. This is particularly the case for networks which have a wide geographic spread, and where different parts of the network are facing different peak demand growth conditions (eg, due to the different composition of load in each area).

Capex to meet enhanced distribution reliability standards in NSW was identified as a key driver for the increase in Essential Energy's capex forecast. The increase in distribution network reliability standards in both NSW and Queensland has also contributed to the increase in capex allowances to meet higher peak demand for some DNSPs. The increase in standards also contributed to an overspend in capex in the previous regulatory period for the Queensland DNSPs, which is in turn an 'other factor' driving P_0 increases (see discussion in section 3.4.2).

Table 5.3
Key Drivers of Increase in Capex Allowance – DNSPs

DNSP	New customer connections*	Augmentation to meet peak demand growth	Environmental, safety and statutory obligations	Non-network assets	Asset renewal/ replacement	Quality, reliability and security of supply enhancement	SCADA & network control
Citipower	✓	✓	-	-	-	-	-
Powercor	✓	✓	✓	-	-	-	-
Jemena	✓	✓	✓	-	-	-	-
SP AusNet	✓	✓	✓	✓	-	-	-
United Energy	✓	✓	✓	✓	-	-	-
Ausgrid	-	✓	-	-	✓	-	-
Endeavour Energy	-	✓	✓	-	✓	-	-
Essential Energy	-	✓	-	-	✓	✓	-
ENERGEX	-	✓	-	-	✓	-	-
Ergon Energy	✓	✓	-	-	✓	-	-
ETSA Utilities	-	✓	-	✓	-	-	-
ActewAGL	-	✓	-	-	✓	-	✓

** Excluding customer contributions*

Table 5.4
Key Drivers of Increase in Capex Allowance – TNSPs

TNSP	New customer connections*	Augmentation to meet peak demand growth	Environmental, safety and statutory obligations	Asset renewal/ replacement	Quality, reliability and security of supply enhancement	Network IT and communications (SCADA)
SP AusNet	-	-	✓	✓	-	-
Ausgrid	-	✓	-	✓	✓	-
TransGrid	-	✓	-	✓	-	-
ElectraNet	✓	✓	-	✓	-	✓
Transend	✓	✓	-	-	-	-

** Excluding customer contributions*

5.3. The AER's assessment of the key drivers for increases in capex allowances

We have undertaken additional analysis in relation to those NSPs with P_0 increases above 15%, as indicated by our recalculated P_0 analysis (discussed in section 2.2). These NSPs are: Ausgrid,[29] Essential Energy, Ergon Energy, ENERGEX, ETSA Utilities, Endeavour Energy, ActewAGL, SP AusNet,[30] ElectraNet, Transend and TransGrid.

For each of these NSPs, we have assessed the extent to which the P_0 increase has been due to the increase in capex allowance between the current and previous regulatory periods. We have identified the increase in capex allowance as a major driver for the overall P_0 increase in the case of Ausgrid (both transmission and distribution), Essential Energy and ETSA Utilities.[31]

For these NSPs, we have then gone on to review:

- the reasons given by the NSP for the required increase in capex allowance, as set out in its initial regulatory submission to the AER; and
- the AER's assessment in its Draft and Final Decisions of the key drivers of the increase in the NSP's forecast capex, including any substantiating analysis it commissioned from independent consultants.

The focus of our review is on understanding to what extent the allowed increase in the capex allowance between regulatory periods for these NSPs reflects circumstances that the AER has determined are reasonable and justify the increased capex allowance, rather than indicating a shortcoming in the regulatory framework.

The detailed results of our analysis are set out below. However in summary we have found that:

- For **Ausgrid** (both transmission and distribution): the key drivers of the increase in capex allowance were (i) asset renewal/replacement; and (ii) augmentation to meet peak demand growth – with these two categories accounting for approximately 80% of the overall increase in the approved total capex forecast;
- For **Essential Energy**: the key drivers of the increase in capex allowance were (i) augmentation to meet peak demand growth; (ii) quality, reliability and security of supply enhancement; and (iii) asset renewal/replacement – with these three categories accounting for approximately 87% of the overall increase in the approved total capex forecast;
- For **ETSA Utilities**: the key drivers of the increase in capex allowance were (i) augmentation to meet peak demand growth; and (ii) non-network capex - with these two

[29] Both distribution and transmission.

[30] Both distribution and transmission.

[31] We have considered the impact of the increase in capex allowances to be a 'major' driver of P_0 increases for these businesses where it has resulted in a P_0 of more than 10%. We note that this cut-off point is essentially arbitrary and has been adopted only in order to contain the analysis, and to focus our review on the key drivers of the larger network price increases.

categories accounting for approximately 69% of the overall increase in the approved total capex forecast

For all three NSPs, the key drivers of the increase in capex forecast were examined by independent engineering consultants appointed by the AER, with both the consultants and the AER concluding that the capex allowance for these categories reflected the prudent and efficient level of expenditure. The evidence therefore indicates that for these NSPs, the key drivers of the increase in capex allowances, and ultimately network price increases, reflect circumstances (eg, increases in peak demand; asset condition) which were recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime.

5.3.1. Ausgrid

The increase in the real capex allowance in the current regulatory period for Ausgrid's distribution business was $3.58bn (June 2009$)(ie, 85%). The increase in capex allowance accounted for 18.6% of the overall 58.3% P_0 increase in Ausgrid's distribution charges.

The information template completed by Ausgrid identifies the key drivers for the increase in Ausgrid's distribution capex allowance as:

- Asset renewal/replacement – which increased from $1.2bn to $2.9bn (June 2009$). This category contributed 56% of the total increase in the real capex allowance; and
- Augmentation to meet peak demand growth - which increased from $1.7bn to $2.4bn (June 2009$). This category contributed 24% of the total increase in the real capex allowance.

Overall these two categories account for approximately 80% of the total increase in real capex forecast.

The increase in the real capex allowance in the current regulatory period for Ausgrid's transmission business was $783m (June 2009$)(ie, 195%). The increase in capex allowance accounted for 29.9% of the overall 46.8% P_0 increase in Ausgrid's transmission charges.

As with distribution, the information template completed by Ausgrid identifies the key drivers for the increase in Ausgrid's transmission capex as:

- Asset renewal/replacement – which increased from $158m to $573m (June 2009$). This category contributed 53% of the total increase in the real capex allowance; and
- Augmentation to meet peak demand growth - which increased from $177m to $327m (June 2009$). This category contributed 19% of the total increase in the real capex allowance.

Overall these two categories account for approximately 72% of the total increase in real capex forecast.

5.3.1.1. Asset renewal/replacement capex

Ausgrid (known at the time as EnergyAustralia) specified asset age and condition as the primary driver for renewal/replacement capex in its initial regulatory proposal.[32] In particular Ausgrid highlighted that the key drivers of replacement capex were the need to replace or convert 11kV switchboards incorporating oil-filled switchgear and the need to replace oil and gas-filled transmission and sub–transmission cables due to their poor circuit availability.[33] Ausgrid also noted that sections of its network were at or near the end of their lives and that failure to replace the aged equipment would result in increasing levels of functional failures, with associated safety, reliability and cost impacts.[34]

The AER retained Wilson Cook in an external consultant role to review Ausgrid's proposed replacement capex. Wilson Cook undertook a detailed review of a number of particular projects in the area plans and in each instance considered the replacement capex proposed by Ausgrid to be prudent and efficient.[35] Further, Wilson Cook also reviewed in detail a number of the sub-programs in Ausgrid's replacement plan and in each instance considered the replacement capex proposed by Ausgrid to be prudent and efficient.[36]

The AER summarised Wilson Cook's position on Ausgrid's proposed replacement capex as follows: [37]

> *"In reviewing EnergyAustralia's proposed replacement capex Wilson Cook was satisfied that EnergyAustralia had followed reasonable policies and procedures that included the identification of need and the determination of least-cost solutions.*
>
> *Wilson Cook considered that EnergyAustralia's proposed replacement capex (and its implicit timing) appeared reasonable. It considered that the consistent and rising trend in replacement expenditure was matched to EnergyAustralia's understanding of the age and condition of its network and the ability of EnergyAustralia to resource the substantial scope of works. Furthermore Wilson Cook considered that the scope of replacement work proposed was generally consistent with the reported fault rates and trends observed.*
>
> *In summary, Wilson Cook was satisfied that the scope of replacement work proposed by EnergyAustralia was prudent and efficient."*

The AER stated it is draft determination that it was "satisfied that the proposed replacement forecast capex reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives".[38]

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32 EnergyAustralia, (2008), *Regulatory Proposal*, 2 June 2008, p. 55,

33 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 479

34 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 480

35 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 481

36 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 481 – 482.

37 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 482.

38 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 483.

5.3.1.2. Augmentation to meet peak demand growth

Ausgrid also identified peak demand growth as a major driver of future capex.[39]

In assessing Ausgrid's proposed growth capex, the AER retained Wilson Cook as an external consultant. The AER also retained McLennan Magasanik Associations (MMA) to conduct a separate independent review of Ausgrid's demand forecasts. In summary, MMA found Ausgrid's peak demand forecasts to be reasonable and acceptable for the purposes of assessing its augmentation capex proposal for the next regulatory control period.[40]

In its review of Ausgrid's proposed growth capex, Wilson Cook examined a number of Ausgrid's area plans in detail and in each instance concluded that the growth capex proposed by Ausgrid was prudent and efficient.[41] Wilson Cook also reviewed Ausgrid's 11 kV network development model, customer connections plan, low voltage capacity plan and property plan and it considered that they were well established documents that set out a prudent and efficient development strategy for the network and its related facilities.[42]

The AER summarised Wilson Cook's position on Ausgrid's proposed growth capex as:[43]

> *"Wilson Cook considered that the analysis undertaken by EnergyAustralia was comprehensive for the type of assets concerned. Importantly, Wilson Cook considered that EnergyAustralia appropriately determined the need for the proposed growth related projects, gave consideration to the least cost options, considered the optimal timing of the projects and maintained consistency with its policies and broader plans."*

In its draft determination, the AER stated that:[44]

> *"The AER has reviewed EnergyAustralia's supporting documentation, including its area plans, 11kV network development model, customer connections plan, low voltage capacity plan and property plan, and engaged in discussions with EnergyAustralia about its growth-related capex. The AER has also considered the advice provided by Wilson Cook and its own assessment of the impact of demand forecasts on the timing of specific projects. Taking into account all of these factors, the AER is satisfied that the proposed growth-related capex reasonably reflects the efficient costs a prudent operator, in the circumstances of EnergyAustralia, would require to achieve the capex objectives and is based on a realistic expectation of demand forecasts and cost inputs, consistent with the capex criteria in clause 6.5.7(c)."*

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39 EnergyAustralia, (2008), *Regulatory Proposal*, 2 June 2008, p. 55,

40 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 476.

41 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 477.

42 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 477.

43 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 477.

44 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 479.

5.3.2. Essential Energy

The increase in the real capex allowance in the current regulatory period for Essential Energy was $1.59bn (June 2009$) (ie, 71%). The increase in capex allowance accounted for 15.7% of the overall 49.7% P_0 increase.

The information template completed by Essential Energy identifies three categories of capex as being primarily responsible for the increase in forecast capex, ie:

- Augmentation to meet peak demand growth– which increased by $762m to $1,341m ($June 2009), contributing 37% of the total increase in real capex;
- Quality, reliability and security of supply enhancement - which increased by $429m to $875m ($June 2009), contributing 28% of the total increase in real capex; and
- Asset renewal/replacement capex - which increased $444m to $795m (in $June 2009), contributing 22% of the total increase in real capex.

Overall these three categories account for approximately 87% of the total increase in real capex forecast.

5.3.2.1. Augmentation to meet peak demand growth

In its initial regulatory proposal, Essential Energy (then known as Country Energy) submitted that the key driver of capex relating to peak demand growth was the forecast annual growth rate for summer and winter peak demand of 3.0% and 1.8%, respectively, for the next regulatory control period, with a shift from a winter to a summer system peak expected during 2012–13.[45] Growth related programs proposed by Essential Energy for the regulatory period included:[46]

- New sub–transmission lines, and capacity and thermal upgrades to existing lines, looping of the network at the sub–transmission level and powerline route and easement acquisitions for future works.
- Construction of new zone substations and capacity upgrades to existing ones, installation of capacitor banks, upgrading of zone substation switchgear and protection systems and land purchases for future substation sites.
- Construction of new urban distribution feeders and interconnections between existing ones to create a meshed network to address shortfalls in load transfer capabilities, upgrading of existing urban feeders, extension and uprating of existing rural feeders facing capacity constraints, new and upgraded distribution substations, and transformers and new augmented low voltage circuits.
- Installation of customer metering for new residential, commercial and industrial developments and connections and installation of load control equipment.

[45] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 135-136.

[46] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 438.

The AER engaged Wilson Cook in an external consultant role to review the augmentation proposed by Essential Energy to meet peak demand. Wilson Cook noted that, unlike the other DNSPs, Essential Energy has a very large service region defined by numerous small networks and a commensurately large number of smaller capex projects and, as a result, they adopted a sampling approach focussing on the projects representing the largest investment during the next regulatory control period.[47] The AER summarised Wilson Cook's conclusions on the two sub-categories of capex projects and programs sampled (sub-transmission augmentation and distribution) as follows:[48]

> *"Wilson Cook concluded that the proposed work [sub-transmission augmentation] was unexceptional and supported adequately by documentation and explanation. It concluded that there were no grounds on which to deem that the costs applied to Country Energy's growth capex program were inefficient…Wilson Cook considered that Country Energy's expenditure under the categories of distribution lines, low voltage lines and customer metering and load control is in line with levels incurred during the current regulatory control period, and therefore considered the projections to be reasonable."*

Taking Wilson Cook's advice into account, the AER stated in its draft determination that it "considers the proposed augmentation capex program reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives".[49]

5.3.2.2. Quality, reliability and security of supply enhancement

In its initial regulatory proposal, Essential Energy stated that the increase in capex required for quality, reliability and security of supply enhancement was being driven by the need to comply with design planning and reliability criteria licence conditions, requiring reinforcement of the distribution network to N-1 standards, remediation of individual poor performing feeders and improvement of average feeder reliability.[50] Specifically, Essential Energy proposed five key reliability and quality of supply investment programs for the regulatory control period: [51]

1. Urban distribution reinforcement program to satisfy N-1 security of planning criteria for high voltage distribution feeders in regional centres (as set out in their licence conditions);
2. Improving average feeder reliability performance of urban and short rural feeders, to a 20% probability of exceeding the SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency index) targets set in the licence conditions;
3. Maintaining an average feeder reliability performance for long rural feeders, to meet the SAIDI and SAIFI targets set in the licence conditions;
4. Improving individual feeder reliability performance for SAIDI and SAIFI towards the standards set in the licence conditions; and

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[47] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 438.

[48] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 439-440.

[49] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 441.

[50] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 444.

[51] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 444-445.

5. System wide steady-state voltage improvement program.

The AER had Wilson Cook review Essential Energy's proposed quality, reliability and security of supply enhancement capex. Wilson Cook concluded that the capex associated with all five of the reliability and quality of supply investment programs was reasonable.[52]

Taking Wilson Cook's advice into account, the AER concluded in its draft determination: [53]

> *"[T]hat Country Energy's proposed projects and programs are necessary to maintain the ongoing security and reliability of its network, and to meet statutory obligations, and reasonably reflect the efficient costs required by a prudent operator to meet the capex objectives. In reaching this conclusion, the AER has considered the advice of Wilson Cook with respect to the efficiency of the expenditure and also the analysis undertaken by Country Energy regarding the prudence of its targeted level of compliance with the licence conditions relating to average feeder reliability."*

5.3.2.3. Asset renewal/replacement capex

In its initial regulatory proposal, Essential Energy specified approximately $814 million of capex for asset renewal/replacement.[54] Specifically, Essential Energy noted that "the need for asset renewal is largely brought about by the physical condition and age of the in service asset and/or component item".[55]

In reviewing Essential Energy's initial proposal for asset renewal/replacement capex, the AER engaged Wilson Cook to undertake an independent review. Wilson Cook reviewed each category of proposed renewal and replacement expenditure and concluded that the scope of the proposed works were 'reasonable and efficient'.[56]

Taking Wilson Cook's advice into account, the AER concluded in its draft decision that:[57]

> *"Country Energy's proposed renewal and replacement programs are necessary to maintain the ongoing security and reliability of its network, and to meet reliability obligations. The AER is satisfied that this aspect of Country Energy's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives."*

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[52] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 448.

[53] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 449.

[54] Country Energy, (2008), Country Energy's Electricity Network Regulatory Proposal 2009-2014, 2 June 2008, p. 144.

[55] Country Energy, (2008), Country Energy's Electricity Network Regulatory Proposal 2009-2014, 2 June 2008, p. 105.

[56] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 443.

[57] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 444.

5.3.3. ETSA Utilities

The increase in the real capex allowance in the current regulatory period for ETSA Utilities was $824m (June 2010$) (ie, 107%). The increase in capex allowance accounted for 10.6% of the overall 36.4% P_0 increase.

The information template completed by ETSA Utilities identifies the following main drivers of the increase in capital allowance:

- Augmentation to meet peak demand growth - increased from $204m to $615m ($June 2010), contributing 50% of the total increase in real capex; and
- Non-network asset capex - increased from $173m to $331m ($June 2010), contributing 19% of the total increase in real capex.

These two categories accounted for almost 70% of the total increase in real capex between the regulatory periods.

5.3.3.1. Augmentation to meet peak demand growth capex

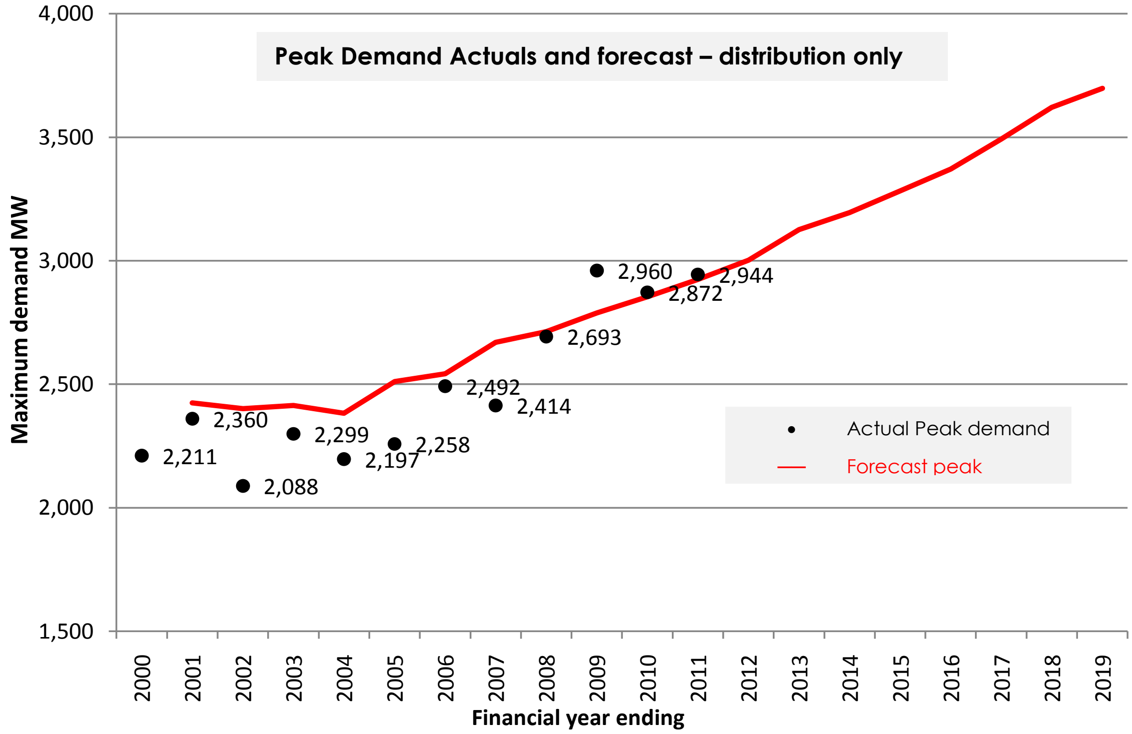
ETSA Utilities proposed $776m of 'capacity' demand driven capex in its initial regulatory proposal, to respond to peak demand growth.[58] The proposed increase was attributed to peak demand growth, changes to the South Australian Electricity Transmission Code requiring downstream work on ETSA's distribution network, and the need to alleviate forecast network constraints (due to network utilisation approaching maximum prudent limits).[59]

Figure 5.3 shows the historical and forecast growth in peak demand across ETSA Utilities' distribution network.

[58] AER, (2009), *South Australia Draft Distribution Determination 2010–11 to 2014–15*, Draft Decision, 25 November 2009, p. 128. 'Capacity' demand driven capacity encompasses capex required to meet peak demand growth. The other category classed as 'demand driven' capex in the case of ETSA was customer connections.

[59] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, Draft Decision, 25 November 2009, p. 128.

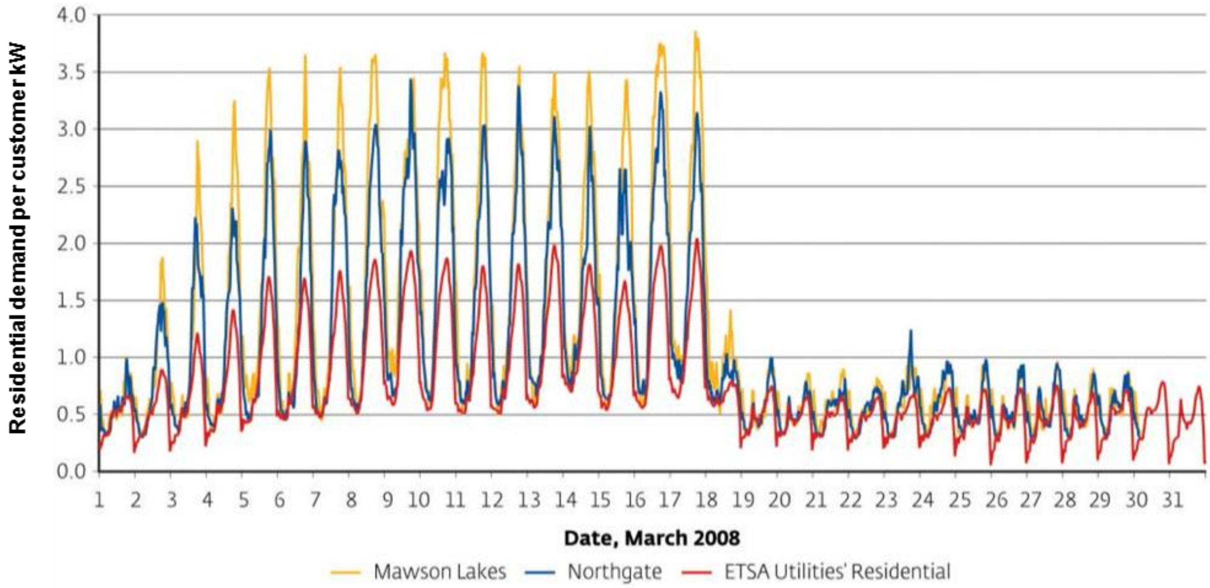
Figure 5.3
ETSA Utilities Peak Demand – Actuals and Forecast, 2000-2019



Source: ETSA Utilities

Figure 5.4 shows the change in demand that occurs in South Australia during extended heatwaves. We understand from ETSA Utilities that this step up in demand is primarily driven by the very high penetration rate of airconditioners (which are constantly being upgraded in size) combined with the poor passive performance of modern dwellings during heatwaves. This is evidenced by the higher peak demand in more modern suburbs (such as Mawson Lakes, shown by the yellow line in Figure 5.4) compared with the state average (shown by the red line in Figure 5.4).

Figure 5.4
ETSA Utilities – Change in Demand in South Australia during Extended Heatwaves



Source: ETSA Utilities.

As part of the draft decision process, the AER retained Parsons Brinkerhoff (PB) to review ETSA's capacity related capex. Specifically, PB:[60]

- assessed whether ETSA Utilities was acting efficiently in accordance with good electricity industry practice, through a review of capital governance, policy and procedures, cost estimating practices, and specific reviews of certain expenditures;
- assessed whether there was a justifiable need for the proposed capital investment within each expenditure category;
- after confirming the need for a capital investment, assessed whether all reasonable options have been considered and the most efficient investment selected to satisfy that need; and
- where a capital investment was based on assumptions about future conditions, assessed whether those assumptions were reasonable.

In the case of ETSA Utilities' proposed demand-driven capex, PB found that ETSA's planning criteria, capex governance, options analysis and cost estimation procedures were all appropriate. The only adjustments recommended by PB were to the low voltage network upgrade program (which represented 16% of the overall expenditure proposed to meet peak demand).[61] Specifically, PB noted that ETSA's risk assessment underpinning the low voltage

[60] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, Draft Decision, 25 November 2009, p. 111.

[61] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, Draft Decision, 25 November 2009, p. 134.

capacity upgrade program overstated the risk, and ETSA proposed low voltage planning criteria were more conservative than those applied by other Australian DNSPs.[62]

In the final decision, the AER concluded that it was satisfied that reducing ETSA's proposed demand driven capex by $39 million (to reflect adjustments to the capex proposed for the low voltage network) would result in expenditure that reasonably reflects the capex criteria.[63]

In its media release in relation to the South Australia distribution determination issued on 6 May 2010 the AER stated:[64]

> *"More than half of this expanded [capex] program is required to ensure the capacity of the network meets future demand from both new and existing customers, including meeting the continuing growth in peak demand. The load is growing as customers continue to install air conditioners and other appliances. In addition, there is need to address risks associated with ageing assets to maintain reliability for customers."*

5.3.3.2. Non-network asset capex

In its initial regulatory proposal, ETSA proposed non-system capex of $364 million - an increase of 98% from the level of non-system capex proposed in the earlier regulatory period. This represented approximately 13% of the total proposed capex program and included expenditure on information technology, property, fleet, and plant and tools.[65]

Specifically, ETSA Utilities has identified the key drivers of the increase of non-network capex as:[66]

- Renewal of major IT systems, IT support for increased network capital program, new Network Operations Centre;
- Existing property maintenance and upgrades. To meet changing field requirements, relocation of existing depots, establishment of new offices and depots;
- New vehicles for increases employee numbers and capital program, legislative required updates to vehicles; and
- Plant and Tools associated with new vehicles, building plant.

In assessing ETSA's proposed non-system capex, the AER retained PB in an independent reviewer role. PB found ETSA's initially proposed non-system capex to be prudent and efficient and did not recommend any adjustments to the proposed expenditure on that basis.[67] Specifically, the AER summarised PB's view as:[68]

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62 AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, Final Decision, May 2010, p. 74.

63 AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, Final Decision, May 2010, p. 79.

64 AER Media Release, 6 Mat 2010 – available at: http://www.aer.gov.au/content/index.phtml/itemId/736389/fromItemId/746345

65 AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 166.

66 Information provided by ETSA Utilities in survey template to NERA.

67 AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, pp. 168-169.

68 AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 113.

> *"PB has assessed ETSA Utilities' proposed non–system capex, including capex for information systems, plant and tools, property and fleet categories, and found the proposed non–system capex to be prudent and efficient. A reduction of $25 million (6%) to the non–system capex is recommended to reflect inefficiencies in the application of the real cost escalators and the errors in the adjustment of the capex forecast to a 2009–10 basis."*

In its draft determination, the AER noted PB's conclusion and itself concluded that ETSA's proposed non-system capex was prudent and efficient, although the AER did make an adjustment to real cost escalators of $107m.[69] Further, the AER noted the cyclical nature of certain elements of the non–system capex, such as costs associated with the replacement of IT systems and the timing of fleet replacement expenditures.[70]

ETSA reflected the AER draft determination findings for non-system assets in its revised regulatory proposal.[71]

[69] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 171.

[70] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 171.

[71] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 70.

6. Drivers of the Increase in Opex Allowances

The analysis in section 3.3 highlights that the increase in opex allowances in the current regulatory period compared to the previous regulatory period has had a substantive impact on P_0 increases.

As in the case of capex allowances, we have sought to identify the drivers behind the increase in opex allowances. Again, we first assess if changes in real costs are a significant component of the increases in opex allowances. We then look at the other key drivers of the increase in opex allowances.

6.1. Real cost escalation

Part of the increase in the opex allowances in the current regulatory period is due to real cost escalation. In particular, materials costs, construction costs, land and labour rates have generally been increasing in real terms.

As discussed in section 5.1 above, in order to estimate how much of the increase in opex allowance is due to real cost escalation, we have used real cost indices commissioned by ENA from SKM. SKM have developed ‘typical’ transmission and distribution network capex and opex real cost escalators. The real cost indices developed by SKM are reproduced in Appendix C.

Table 6.1 sets out the increase in the real opex allowance between the current and previous regulatory periods for each DNSP.

Table 6.1
Change in Opex Allowance Due to Real Cost Escalation - DNSPs

Business	Change in real opex
Ausgrid	1.9%
Essential Energy	1.9%
ActewAGL	2.0%
Endeavour Energy	1.9%
ENERGEX	2.0%
Ergon Energy	2.1%
ETSA Utilities	2.1%
United Energy	2.4%
CitiPower	2.4%
Powercor	2.4%
SP AusNet	2.2%
Jemena	2.1%

Table 6.2 provides the same breakdown for TNSPs.

Table 6.2
Change in Opex Allowance Due to Real Cost Escalation - TNSPs

Business	Change in real opex
Ausgrid	1.9%
ElectraNet	3.1%
Transend	1.9%
TransGrid	1.9%
SP AusNet	3.5%

It is evident from the above that, unlike capex, increases in real costs are a driver of the increase in the opex allowance in the most recent regulatory period. However, they are only a modest driver – estimated to contribute real increases of between 1.9% and 2.4% for DNSPs and between 1.9% and 3.5% for TNSPs of total opex.

As discussed earlier, the AER is not constrained under the Rules in substituting its own real cost escalation indices. Indeed, the AER has chosen to substitute its own real cost escalators in all of its final determinations for DNSPs and TNSPs. As a consequence, the increase in network charges due to the impact of real cost escalation on opex allowances does not indicate a shortcoming in the operation of the Rules.

6.2. Key drivers of the increase in opex allowances

Part of the survey template circulated to the DNSPs included a breakdown of the opex allowance in the current and previous regulatory periods into base year and step-changes.

Table 6.3 presents the percentage of the total opex allowance due to step-changes. It is evident from this analysis that the importance of step-changes in driving overall opex allowances varies across DNSPs.

Table 6.3
Step-changes as a Percentage of Total Opex Allowance – DNSPs

Business	Proportion
SP AusNet	22%
ETSA Utilities	20%
Jemena	13%
ENERGEX	16%
Essential Energy	15%
ActewAGL	14%
Powercor	11%
CitiPower	11%
United Energy	10%
Ausgrid	6%
Endeavour Energy	4%
Ergon Energy	0%

6.3. The AER's assessment of the key drivers for increases in opex allowances

We have again undertaken additional analysis in relation to those NSPs with P_0 increases above 15%, as indicated by our recalculated P_0 analysis.

For each of these NSPs we have assessed the extent to which the P_0 increase has been due to the increase in opex allowance between the current and previous regulatory periods. We have identified the increase in opex allowance as a major driver for an overall material P_0 increase in the cases of Ausgrid (distribution), ActewAGL, ETSA Utilities, and Transend.[72]

For these NSPs, we have reviewed:

- the reasons given by the NSP for the required increase in opex allowance, as set out in its initial regulatory submission to the AER; and
- the AER's assessment in its Draft and Final Decisions of the key drivers of the increase in the NSP's forecast opex, including any substantiating analysis it commissioned from independent consultants.

The focus of this analysis is again on understanding to what extent the allowed increase in forecast opex between regulatory periods reflects circumstances that the AER has determined are reasonable and justify the allowed increase, rather than indicating a shortcoming in the Rules.

In summary, we have found that the drivers behind the increase in opex reflect a combination of factors, such as real wages growth (increased legislative obligations (including feed-in tariffs) and an expansion of the capital base). For the businesses we reviewed, in all cases the AER had the NSP's forecasts reviewed by independent consultants. In the case of Transend, ActewAGL, ETSA Utilities and Essential Energy, the AER applied reductions to the allowed opex forecast over and above those that had been recommended by the external consultants.

6.3.1. Transend

Our PTRM analysis indicates that Transend's transmission revenues have increased approximately 32.5% since the previous regulatory period. Of the three factors investigated, changes in forecast opex were found to have had the greatest impact on this revenue increase. Specifically, treating every other change between periods as given, the increase in the real forecast operating expenditure alone would have resulted in a 10.6% increase in Transend's revenues.

Transend's initial regulatory proposal included forecast opex of \$281 million.[73] Transend identified the following high level drivers of the increase in forecast opex:[74]

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[72] We have considered the impact of the increase in opex allowances to be a 'major' driver of P_0 increases for these businesses where it has contributed more than 10% of the overall change in P_0. We note that this cut-off point is essentially arbitrary and has been adopted only in order to contain the analysis, and to focus on the drivers of the larger network price increases.

[73] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 158.

- Increasing real wage growth, driven by skills shortages in Australia;
- Increasing asset growth and additional resources to support capital program and systems control;
- Increased legislative obligations (such as compliance with the *Electricity Supply Industry (Network Performance Requirements) Regulations 2007*); and
- Other changing circumstances and obligations.

As part of the information gathering component of this assignment, Transend informed us that the allowance provided by the ACCC for the previous (ie, 2004-09) regulatory period was considered by Transend to provide unsustainably low expenditure allowances and , as a result, Transend incurred actual expenditure throughout the regulatory period which was greater than the allowance provided (which included increased costs associated with preparing for Tasmania's entry into the NEM and associated ongoing obligations). In fact, during the review of Transend's initial proposal for the current period, the AER's consultants, WorleyParsons stated in their report that:[75]

> *"WorleyParsons has studied the ACCC Decision on the level of Opex expenditure in the Current Regulatory Control Period, and does not understand the basis for that Decision."*

In its draft decision, the AER stated that it had compared Transend's opex in 2006-07 (the base year) against the efficient amount forecast in the 2003 revenue cap decision and Transend's actual opex in 2006-07 was $7.2 million higher than the efficient forecast amount in the ACCC decision of $33.3 million.[76] In its draft decision, the AER found that Transend's actual base year expenditure was efficient, effectively confirming that the ACCC decision allowance was insufficient.

Further, as part of its draft decision, the AER engaged WorleyParsons to provide an independent review of Transend's opex proposal. WorleyParsons reviewed Transend's business model, maintenance policies and processes, concluding that Transend was a relatively efficient TNSP.[77] Further, WorleyParsons concluded that the methodology and resulting forecast for all major[78] categories of controllable opex were considered reasonable.[79] WorleyParsons only recommended one minor adjustment to Transend's forecast opex, which was a reduction for one inventory officer position and totalled $0.4 million over the regulatory period (less than 1% of Transend's total proposed opex).[80]

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74 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 159.

75 WorleyParsons, (2008), *REVIEW OF THE TRANSEND TRANSMISSION NETWORK REVENUE PROPOSAL 2009 - 2014*, 23 October 2008, p. 12.

76 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 166.

77 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 161.

78 Major categories are: field maintenance & operations; transmission services; transmission operations; asset management; and corporate.

79 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 180-184.

80 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 161-162.

In its draft decision, the AER concluded that Transend's forecast total opex did not reasonably reflect the opex criteria and applied various reductions totalling $21.2 million (7.5%) to determine a total opex forecast of $260.2 million for the period.[81] As part of its draft decision, the AER made specific reductions to the labour escalation rates applied to controllable opex.[82]

Transend included a total opex forecast of $283 million as part of its revised opex proposal, which accepted most aspects of the AER's draft decision relating to forecast opex, except for:[83]

- Debt and equity raising costs;
- Labour and non-labour escalators; and
- Labour escalation for telecommunication costs.

As part of its final decision, the AER engaged a number of external consultants to review various aspects of Transend's revised opex proposal and concluded that the telecommunication costs submitted by Transend as well as the electricity, gas and water labour cost escalators submitted reasonably reflected the opex criteria.[84] However, overall, the AER concluded that it was not satisfied that Transend's total forecast opex reasonably reflected the opex criteria and applied a $29 million (10.2%) reduction to Transend's total forecast opex, comprising of:[85]

- a reduction of $11 million to equity raising costs - equity raising costs were removed from opex and the amount of equity raising costs calculated by the AER was capitalised; and
- a reduction of $18 million arising from the modelling - reflecting changes to asset growth (resulting from amended capex allowance), actual CPI for 2007–08 and 2008–09, removal of replacement capex for transitional services, and debt raising costs (resulting from amended capex allowance).

6.3.2. Essential Energy

Our PTRM analysis indicates that Essential's distribution prices have increased approximately 49.7% since the previous regulatory period. Of the three factors investigated, changes in forecast opex were found to have had the most significant effect on this price increase. Specifically, treating every other change between periods as given, the increase in the real forecast operating expenditure alone would have resulted in a 20.2% increase in Essential's prices.

81 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 200-203.

82 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 202.

83 AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. xv.

84 AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, pp. 95 & 101.

85 AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, 2008, pp. 121-122.

As part of the information gathering component of this assignment, we understand from Essential that step changes made up approximately 15% of the total allowed opex in the current regulatory period. Further, Essential informed us that the opex increase between periods was primarily caused by increases in vegetation management, maintenance and repairs and inspections. Specifically, Essential informed us that vegetation management accounted for the largest part of the increase in opex between the regulatory periods and that it increased for the following reasons:

- The introduction of Design, Reliability and Performance Licence Conditions which included the requirement for compliance with the feeder class reliability standards as well as the individual feeder reliability standards;
- Insufficient vegetation management costs had been included in Country Energy's previous regulatory proposal. This was due to the fact that Country Energy was formed in 2001 and the historical vegetation spends of the 3 predecessor organsisations did not accurately reflect the expenditure necessary to comply with the Industry Safety Steering Committee;
- Improved safety standards; and
- A new methodology was developed to more accurately forecast vegetation management expenditure requirements just prior to submitting the regulatory proposal for the 2009 to 2014 determination period.

Essential's initial regulatory proposal included a forecast opex amount of $2,160 million.[86] Of this total amount, approximately 98% was classified as 'controllable opex.' Essential identified the following significant drivers of controllable opex: [87]

- new, deferred and backlog asset inspection and maintenance works to mitigate risk and improve network performance;
- cost increases above inflation for labour and input materials; and
- increased workload due to additional assets.

As part of the draft decision, the AER engaged Wilson Cook to to review the controllable opex components of Essential's forecast opex proposal. Wilson Cook made the following comments with respect to Essential's proposed maintenance and repairs opex:[88]

> *"We reviewed the asset management plans and policies and the principles applied to the risk-based model used to derive the work programme. We found the maintenance strategies and processes used by Country Energy to be typical of electricity distribution businesses. Inspection cycles and routine maintenance activities were in line with industry standards. The process used to review and identify maintenance requirements appeared to be robust and appropriate. Based on our review, we are satisfied that Country Energy's maintenance policies and processes are appropriate and properly applied."*

[86] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 159.

[87] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 160.

[88] Wilson Cook & Co, (2008), *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 4 – Country Energy, p. 40

Wilson Cook also made the following comments with respect to Essential's proposed inspections opex:[89]

> *"The new programmes include new initiatives to widen the scope of the inspection programme, including programmed internal inspection of all underground pits and pillars, six-monthly condition monitoring of critical distribution substations and ring main units, programmed live-line pole-top inspection of all radial sub-transmission feeders, a 'thermo vision' programme covering all critical equipment and urban network components and six monthly condition monitoring of all regulators and reclosers… We consider the increased scope of the proposed programmes reasonable and should enable the company to identify risks earlier and improve system performance."*

Further, Wilson Cook noted the following with respect to Essential's proposed vegetation management opex:[90]

> *"We have reviewed all the information provided on the vegetation management forecast. Much of the increased programme is new and targeted at different purposes to the historical programme. It will take some years before it can be established that the programme achieves the reliability improvements being targeted but use of the profiling data does provide a reasonable basis for estimating the required works."*

Overall, Wilson Cook concluded that its top-down review suggested that Essential's base year level of expenditure was low and may be below a prudent level to maintain targeted service levels.[91] However, Wilson Cook did recommend a $30 million reduction (1%) to the forecast controllable opex, as it did not consider that it was appropriate for Essential to apply an asset growth escalator to vegetation management, as it was unlikely that the quantity of vegetation management would be driven principally by growth capex.[92]

In its draft decision, the AER concluded that it was not satisfied that Essential's total forecast opex reasonably reflects the opex criteria. Taking into account Wilson Cook's advice as well as their own analysis, the AER applied a reduction of $185 million ($8.6%) to Essential's proposed opex.[93] Specifically, the AER's adjustment was comprised of the following components:[94]

- $135 million reduction to deferred expenditure (inspections, maintenance & repair and vegetation management);[95]

89 Wilson Cook & Co, (2008), *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 4 – Country Energy, p. 40

90 Wilson Cook & Co, (2008), *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 4 – Country Energy, p. 41.

91 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 167.

92 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 167.

93 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 198.

94 Unless otherwise stated: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 198-199.

95 Unless otherwise stated: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 174.

- a $25 million reduction to vegetation management escalation;
- an $8 million reduction to input cost escalators;
- a $12 million reduction to debt raising costs; and
- a $5 million reduction to self-insurance costs.

Essential did not accept the AER's conclusion on forecast opex in its revised proposal and included a forecast of $2,211 million for the regulatory period.[96] In its revised regulatory proposal, Essential clarified a number of points to the AER in relation to its vegetation management and in its final decision the AER concluded the following:[97]

> *"As such, Country Energy has alleviated the AER's key concerns by demonstrating that it is not proposing that consumers pay for the same service twice. Rather, in the current regulatory control period Country Energy undertook projects that were of a higher priority and provided benefits to customers."*

However, overall, in the final decision, the AER stated it was not satisfied that Essential's revised opex forecast reasonably reflected the opex criteria and, having undertaken its own analysis as well as engaging Wilson Cook and Energy and Management Services, applied a reduction of $159 million to the proposed total opex, ie, a reduction of around 7.2% compared with Essential's revised proposed opex.[98] Specifically, the AER's adjustment was comprised of the following components:[99]

- a $40.2 million reduction to the costs of project associated with Sheather decision;
- a $26 million reduction to vegetation management escalation;
- a $75 million reduction to input cost escalators;
- a $4 million reduction for revised capex forecasts;
- a $12 million reduction to debt raising costs; and
- a $5 million reduction to self-insurance costs.

However, the AER did conclude that the $135 million reduction to deferred expenditure made in the draft decision should be reinstated. Specifically, the AER concluded:[100]

> *"For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is satisfied that the reinstatement of $135 million ($2008–09) for vegetation management expenditure in Country Energy's forecast opex results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors."*

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[96] AER, (2008), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 150.

[97] AER, (2008), *New South Wales Distribution Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. 156.

[98] AER, (2008), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 200.

[99] AER, (2008), *New South Wales Distribution Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, pp. 201-202.

[100] AER, (2008), *New South Wales Distribution Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. 156.

6.3.3. ActewAGL

Our PTRM analysis indicates that, treating other changes between periods as given, the increase in the real forecast operating expenditure for ActewAGL contributed 18.2% to the overall 22.7% increase in network charges. We understand from ActewAGL that approximately 54% of the $108.8 million increase in opex between this regulatory period and the last is attributable to their Feed-in Tariff (FiT) scheme and the Utilities Network Facilities Tax (UNFT).[101]

ActewAGL's initial regulatory proposal included forecast opex of $306 million, which was approximately 36% greater than the forecast opex in the, then, current regulatory period.[102] ActewAGL identified the following significant drivers for the increase in opex in its initial regulatory proposal:[103]

- Increases in real wages and cost of raw materials;
- Asset base growth;
- Introduction of an enhanced pole inspection program; and
- Additional activities associated with the vegetation and bushfire mitigation inspection and management program.

The AER retained Wilson Cook to review ActewAGL's forecast opex, who concluded:[104]

> *"After considering both the "bottom-up" and "top-down" analyses, we accepted that improvements in efficiency will be made over the next period and concluded that the proposed opex should be accepted without adjustment."*

However, having considered the advice Wilson Cook, and undertaking their own analysis, the AER applied a reduction of $9.5 million (around 3%) to ActewAGL's proposed opex.[105]

In their revised proposal, ActewAGL did not accept the AER's conclusion on controllable opex and substituted an amount of $275 million that included: [106]

- revised labour cost escalators;
- new opex relating to service target performance incentive scheme (STPIS) reporting requirements; and
- new opex relating to the implementation of the FiT scheme.

[101] Specifically, ActewAGL informed us that the FiT scheme and UNFT added $47.9 million and $10.8 million respectively (both $2008/09) to the total opex increase between periods.

[102] AER, (2008), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Draft Decision, 7 November 2008, p. 83.

[103] AER, (2008), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Draft Decision, 7 November 2008, p. 84.

[104] Wilson Cook, (2008), *ACT & NSW DNSP Expenditure Review – ActewAGL*, Final Report, October 2008, p. 39.

[105] AER, (2008), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Draft Decision, 7 November 2008, p. 119.

[106] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, pp. 50-51.

Further, ActewAGL also provided revised opex estimates for debt raising costs, equity raising costs, self-insurance and FiT scheme direct tariff payments. In total, ActewAGL's revised proposal increased the total opex forecast by $60 million to $359 million.[107]

In making its final decision, the AER engaged various consultants to review ActewAGL's revised opex forecasts and concluded that it was not satisfied that ActewAGL's forecast total opex reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives.[108] Having considered the advice of the consultants, and undertaking its own analysis of ActewAGL's proposed opex, the AER applied a reduction of $18 million (5%) to ActewAGL's proposed opex.[109]

6.3.4. ETSA Utilities

Our PTRM analysis indicates that, treating other changes between periods as given, the increase in the real forecast operating expenditure for ETSA Utilities contributed 10% to the overall 36.4% increase in network charges.

As part of the information template ETSA completed, it identified that step changes in opex contributed approximately 20% of the total opex allowed in the current regulatory period. ETSA listed the following categories of opex as being major contributors to these step changes:[110]

- Feed in tariffs - $39 million;
- Asset inspections - $26 million;
- IT support - $28 million;
- Property costs & land tax - $21 million; and
- Insurance premiums and support - $21 million.

ETSA's initial regulatory proposal included forecast opex of $1,175 million, which was approximately 60% greater than the forecast opex for the, then, current regulatory period.[111] Of this total amount, approximately 89% was classified as 'controllable opex.' ETSA identified the following significant drivers of controllable opex:[112]

- ETSA submitted that its base year expenditure included a number of unusual expenditures that are likely to understate or overstate ETSA Utilities' longer-term efficient costs, ie,

[107] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 51.

[108] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 84.

[109] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 84.

[110] We note that ETSA also identified network maintenance & planning ($14 million), superannuation contributions ($12 million) and operating support for significant increase in capex as being large contributors to the step changes.

[111] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 182.

[112] Unless otherwise stated: AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, pp. 185-186 & 201 - 202.

vegetation management, telecommunications, debt raising costs, self-insurance, regulatory proposal, demand management and finance adjustments;

- Changing risk profile of the distribution network, ie, intensifying its asset condition monitoring regime;[113]
- Impact of the capex program being substantially greater than the last period;[114]
- Changes associated with economic factors, ie, costs associated with superannuation contributions and insurance premiums were expected to increase significantly due to the global financial crisis;[115]
- Changes in regulatory, legal, or tax obligations, ie, land tax, meter maintenance and feed-in tariffs;[116]
- Changing community expectations through a series of 'formal and informal' methods of engagement with the community;[117]
- Other changes in scope including full retail contestability systems support, aerial inspections and Davenport Training Centre;
- Scale escalation – primarily network growth; [118] and
- Input cost escalation– primarily labour costs.[119]

As part of the draft decision, the AER engaged PB to provide an independent assessment of ETSA's forecast opex proposal. Based on its review, PB found that 96% of ETSA's $1,175 million of proposed opex was prudent and efficient and recommended that the forecast opex be reduced by $46 million (ie, a 4% reduction).[120]

In its draft decision, the AER concluded that it was not satisfied that the opex forecast reasonably reflects the opex criteria, including the opex objectives.[121] The AER concluded that an adjustment in forecast opex to $1,044 million (ie, a reduction of 11% compared with ETSA's initial proposal) would reasonably reflects the opex criteria, being the minimum adjustment necessary for the total forecast opex to comply with the NER.[122]

ETSA did not accept the AER's conclusion on forecast opex in its revised proposal and included a revised forecast of $1,082 million.[123] As part of its final decision, the AER again engaged PB to review the revised opex proposal put forward by ETSA, who recommended

[113] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 158.

[114] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 164.

[115] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 161.

[116] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 162.

[117] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 166.

[118] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 171.

[119] ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 177.

[120] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 189.

[121] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, pp. 243 -245.

[122] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 245.

[123] AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, May 2010, p. 108.

reductions to ETSA's revised proposed opex totalling approximately $12 million (1%).[124] Having considered the advice of PB as well as its own review, the AER made a series of specific adjustments to ETSA's revised opex proposal resulting in a total opex forecast of $1,033 million (ie, 12 % below ETSA's initial proposal) and concluded that it was satisfied this amount reasonably reflected the opex criteria, taking into account the opex factors.[125]

6.3.5. Ausgrid

Our PTRM analysis indicates that the increase in opex forecast for Ausgrid contributed 15.6% to the overall 58.3% P_0 change from the previous regulatory period.

Ausgrid's initial regulatory proposal included a forecast opex amount of $3,047 million. [126] Of this total amount, approximately 97% was classified as 'controllable opex.' Ausgrid identified the following significant drivers of controllable opex:[127]

- Increased workload largely arising from the larger asset base, adding approximately 25% to network maintenance costs;
- Increased network maintenance costs associated with the increasing age of assets;
- Cost increases above inflation;
- Step changes arising from:
  - the higher costs of IT due to the introduction of new systems;
  - an increased property portfolio to meet the expanded capex requirements as well as corporate property expenses; and
  - a need to meet statutory and regulatory obligations.

As part of its draft decision, the AER engaged Wilson Cook to to review the controllable opex components of Ausgrid's forecast opex proposal. The AER summarised Wilson Cook's main findings as:[128]

- Ausgrid's base year opex is at or a little above the industry norm, but could not be considered inefficient;
- Ausgrid's cost efficiency relative to the other NSW and ACT DNSPs will deteriorate and, unless reasons can be established why Ausgrid should move further away from an

[124] Parsons Brinkerhoff, (2010), Review of ETSA Utilities' Revised Regulatory Proposal for the Period July 2010 to June 2015, May 2010, pp. 29 – 41.

[125] AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, May 2010, p. 142.

[126] AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 162. Note that the discussion in this section refers to the total opex proposed by Ausgrid across both their transmission and distribution activities, as these amounts were not separately identified in the AER's draft and final decisions (see: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 174)

[127] Communication with Ausgrid as well as: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 162.

[128] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, pp. 167-168.

industry norm level of opex, the level of opex in the next regulatory control period cannot be considered to be efficient; and

- Wilson Cook proposed adjustments to remove most of the step changes proposed by Ausgrid as they were found not to be supported by considerations of business efficiency improvements or potential cost savings.

In total, Wilson Cook recommended a reduction of $316 million (11%) to Ausgrid's total opex forecast.[129]

Noting Wilson Cook's advice, as well as its own analysis, the AER applied a series of reductions totalling $410 million (13%) to Ausgrid's proposed opex in its draft decision, which resulted in a revised forecast opex allowance of $2,638 million.[130]

In its revised regulatory proposal, Ausgrid rejected all of the reductions made by the AER in its draft decision.[131] Ausgrid proposed a revised total opex allowance of $2,991 million, which represented a reduction of $80 million from its initial regulatory proposal but was $353 million greater than the amount of opex allowed by the AER in its draft decision.[132] Ausgrid's rejection of the AER's adjustments was based on the following arguments:[133]

- The AER and Wilson Cook did not consider all of the material in Ausgrid's initial proposal;
- The AER uncritically relied on Wilson Cook's analysis rather than supplementing it with its own analysis; and
- Much of Wilson Cook's analysis was flawed.

Ausgrid provided additional information in support of its revised regulatory proposal, including four new consultancy reports.

As part of its final decision, the AER again engaged Wilson Cook to review the components of Ausgrid's revised opex proposal. In total, Wilson Cook recommended a reduction of 12% compared with Ausgrid's revised total opex proposal.[134] Based on the advice provided by Wilson Cook as well as their own analysis, the AER applied a reduction of $363 million (around 12%) to Ausgrid's revised total opex proposal, resulting in a revised forecast opex allowance of $2,628 million.[135]

We note that Ausgrid appealed to the Tribunal regarding the AER's final decision on Ausgrid's proposed step changes as well as a number of other minor factors. However, the Tribunal affirmed the AER's decisions in the majority of cases, noting that the only step

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129 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 168.

130 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 199.

131 AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 151.

132 AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 151.

133 AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 152.

134 AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 202.

135 AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 202.

change that should not be reduced to zero was that relating to ‘finance and commercial – business systems’.[136]

[136] Australian Competition Tribunal, (2009), Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8, 12 November 2009, Para. 203.

Appendix A. Results of P_0 Analysis for each NSP

Table A.1
Victoria: Scenario Changes in P_0

	CitiPower	Powercor	JEN	SP AusNet	United Energy	DNSP weighted average	Change	SP AusNet*	Change
P_0 (assume X2-5 = 0)	-1.4%	-6.3%	-11.0%	-19.2%	-5.6%	-9.7%		-15.3%	
(NPV of revenue)	$903.8	$1,907.7	$751.2	$1,872.1	$1,272.0			$2,158.0	
WACC (including franking)	3.4%	-2.2%	-4.4%	-12.9%	-1.8%	-4.6%	-5.1%	-12.0%	-3.2%
(NPV of revenue)	$878.2	$1,871.5	$731.7	$1,822.4	$1,251.3			$2,158.1	
Capex	-0.2%	-2.9%	-9.4%	-12.4%	-1.4%	-5.6%	-4.1%	-12.2%	-3.1%
(NPV of revenue)	$893.0	$1,847.0	$740.4	$1,765.4	$1,221.3			$2,100.2	
Opex	-0.2%	-2.6%	-14.6%	-10.0%	-2.8%	-5.7%	-3.9%	-14.2%	-1.1%
(NPV of revenue)	$892.9	$1,841.6	$775.7	$1,728.4	$1,238.0			$1,763.1	
WACC, Capex & Opex	5.5%	4.4%	-6.8%	2.3%	4.9%	2.7%	-12.4%	-5.5%	-9.8%
(NPV of revenue)	$859.9	$1,750.9	$748.3	$1,578.1	$1,169.3			$1,646.9	

Source: NERA analysis.

** We have assumed middle of the financial year (ending in 31 March) dollars for forecast capex/opex approved in the previous regulatory period and brought them forward to March 2008 dollars. We have also created a '6th year' of capex/opex for the last regulatory period (consistent with the current PTRM) by averaging the 5 years of approved forecasts.*

Table A.2
New South Wales: Scenario Changes in P_0

	Ausgrid	Endeavour Energy	Essential Energy	DNSP weighted average	Change	Transgrid	Ausgrid	TNSP weighted average	Change
P_0 (assume X2-5 = 0)	-58.3%	-32.9%	-49.7%	-49.3%		-18.2%	-46.8%	-24.1%	
(NPV of revenue)	\$6,319.5	\$3,591.6	\$4,515.3			\$2,981.4	\$771.9		
WACC (including franking)	-43.7%	-21.8%	-38.3%	-36.5%	-12.8%	-9.5%	-30.8%	-13.9%	-10.2%
(NPV of revenue)	\$5,964.9	\$3,441.8	\$4,346.4			\$2,837.1	\$728.6		
Capex	-39.7%	-23.4%	-33.9%	-33.7%	-15.6%	-8.8%	-17.0%	-10.3%	-13.8%
(NPV of revenue)	\$5,578.4	\$3,346.2	\$4,044.6			\$2,744.7	\$614.9		
Opex	-42.7%	-23.1%	-29.5%	-33.6%	-15.6%	-14.0%	-42.0%	-19.7%	-4.4%
(NPV of revenue)	\$5,697.4	\$3,337.2	\$3,911.0			\$2,874.0	\$746.3		
WACC, Capex & Opex	-12.2%	-3.8%	-4.5%	-7.6%	-41.7%	2.8%	-3.7%	1.6%	-25.7%
(NPV of revenue)	\$4,658.3	\$2,959.7	\$3,293.9			\$2,517.1	\$559.0		

Source: NERA analysis.

Table A.3
Queensland: Scenario Changes in P_0

	ENERGEX	Ergon Energy	DNSP weighted average	Change
P_0 (assume X2-5 = 0)	-42.6%	-47.5%	-45.0%	
(NPV of revenue)	$5,471.9	$5,109.6		
WACC (including franking)	-23.6%	-29.7%	-26.6%	-18.4%
(NPV of revenue)	$4,933.2	$4,669.3		
Capex	-33.8%	-40.3%	-36.9%	-8.0%
(NPV of revenue)	$5,134.8	$4,858.6		
Opex	-39.9%	-39.6%	-39.8%	-5.2%
(NPV of revenue)	$5,368.8	$4,836.8		
WACC, Capex & Opex	-14.2%	-16.2%	-15.1%	-29.8%
(NPV of revenue)	$4,555.7	$4,183.9		

Source: NERA analysis.

Table A.4
South Australia: Scenario Changes in P_0

	ETSA Utilities	**Change**	**ElectraNet**	**Change**
P_0 (assume X2-5 = 0)	-36.4%		-33.9%	
(NPV of revenue)	$2,879.2		$1,003.8	
WACC (including franking)	-26.0%	-10.4%	-19.8%	-19.2%
(NPV of revenue)	$2,710.9		$914.7	
Capex	-25.8%	-10.6%	-25.4%	-8.5%
(NPV of revenue)	$2,655.5		$940.2	
Opex	-26.3%	-10.0%	-31.2%	-2.7%
(NPV of revenue)	$2,667.1		$983.6	
WACC, Capex & Opex	-7.8%	-28.6%	-10.3%	-28.6%
(NPV of revenue)	$2,319.4		$865.2	

Source: NERA analysis.

Table A.5
Australian Capital Territory: Scenario Changes in P_0

	ActewAGL	Change
P_0 (assume X2-5 = 0)	-22.7%	
(NPV of revenue)	$612.8	
WACC (including franking)	-23.3%	0.6%
(NPV of revenue)	$614.7	
Capex	-18.1%	-4.6%
(NPV of revenue)	$589.9	
Opex	-4.5%	-18.2%
(NPV of revenue)	$521.8	
WACC, Capex & Opex	-0.7%	-22.0%
(NPV of revenue)	$502.3	

Source: NERA analysis.

Table A.6
Tasmania: Scenario Changes in P_0

	Transend	Change
P_0 (assume X2-5 = 0) **(NPV of revenue)**	-32.5% $778.5	
WACC (including franking) (NPV of revenue)	-25.0% $751.4	-7.5%
Capex (NPV of revenue)	-23.4% $724.9	-9.1%
Opex (NPV of revenue)	-21.9% $716.2	-10.6%
WACC, Capex & Opex (NPV of revenue)	-5.9% $639.2	-26.6%

Source: NERA analysis.

Appendix B. Key Drivers of P_0 Increase

B.1. New South Wales

Table B.1 Primary drivers of Ausgrid's Distribution P_0, ($June 2009)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 58.3% price increase			
1. Capex 2004/05 - 2008/09 $3.58b 2009/10 – 2013/14 $6.63b Increase $3.05b, ie, 85%	18.6%	a) Asset renewal/replacement - Increased from $1.2b to $2.9b - 56% of total increase in real capex	
		b) Augmentation to meet peak demand growth - Increased from $1.7b to $2.4b - 24% of total increase in real capex	
2. Opex	15.6%	a) Real cost scale (workload) escalation	
		b) Real cost escalation	
3. WACC	14.6%	Real nominal WACC increased from 6.02% to 7.60% Increase in the DRP contributes 125 basis points to the WACC Increase in the Equity risk premium contributes 38 basis points to the WACC	New benchmark higher quality than that assumed by IPART, ie, IPART assumed BBB+ to BBB 10yr Aus corporate debt. Transitional WACC allowed an equity beta of 1.0 and an MRP of 6%.
Unexplained change in prices = 12.2% increase			

Source: NERA analysis.

Table B.2 Primary drivers of Endeavour Energy's P_0, ($June 2009)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 32.9% price increase			
1. WACC	11.2%	Real nominal WACC increased from 6.02% to 7.60% Increase in the DRP contributes 125 basis points to the WACC Increase in the Equity risk premium contributes 38 basis points to the WACC	New benchmark higher quality than that assumed by IPART, ie, IPART assumed BBB+ to BBB 10yr Aus corporate debt. Transitional WACC allowed an equity beta of 1.0 and an MRP of 6%.
2. Opex	9.9%	'Base year' opex makes up 93% of allowed opex.	
3. Capex <u>2004/05 - 2008/09</u> $1.84b <u>2009/10 – 2013/14</u> $2.72b <u>Increase</u> $880m, ie, 48%	9.5%	a) Augmentation to meet peak demand growth - Increased from $807m to $1,101m - 33% of total increase in real capex	
		b) Environmental, safety and statutory obligations (excluding reliability) - Increased from $140m to $416m - 31% of total increase in real capex	i. NSW Design Planning Licence Conditions - 100% of total increase in this category - Increased from $135m to $411m
		c) Asset renewal/replacement - Increased from $521m to $781m - 30% of total increase in real capex	
Unexplained change in prices = 3.8% increase			

Source: NERA analysis.

Table B.3 Primary drivers of Essential Energy's P_0, ($June 2009)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 49.7% price increase			
1. Opex	20.2%	Inspections, maintenance & repair and vegetation management	
2. Capex 2004/05 - 2008/09 $2.24b 2009/10 – 2013/14 $3.83b Increase $1.59b, ie, 71%	15.7%	a) Augmentation to meet peak demand growth - Increased from $762m to $1,341m - 37% of total increase in real capex	
		b) Quality, reliability and security of supply enhancement - Increased from $429m to $875m - 28% of total increase in real capex	
		c) Asset renewal/replacement - Increased from $444m to $795m - 22% of total increase in real capex	
3. WACC	11.4%	Real nominal WACC increased from 6.02% to 7.60% Increase in the DRP contributes 125 basis points to the WACC Increase in the Equity risk premium contributes 38 basis points to the WACC	New benchmark higher quality than that assumed by IPART, ie, IPART assumed BBB+ to BBB 10yr Aus corporate debt. Transitional WACC allowed an equity beta of 1.0 and an MRP of 6%.
Unexplained change in prices = 4.5% increase			

Source: NERA analysis.

Table B.4 Primary drivers of TransGrid's P_0, ($June 2008)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 18.2% revenue increase			
1. Capex <u>2004/05 - 2008/09</u> $1,350 <u>2009/10 – 2013/14</u> $2,405 <u>Increase</u> $1,055m, ie, 78%	9.4%	a) Augmentation to meet peak demand growth - Increased from $930m to $1,752m - 78% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $274m to $441m - 16% of total increase in real capex	
2. WACC	8.7%	Real post-tax WACC increased from 6.48% to 7.62%. Increase in the DRP contributes 125 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A- 10yr Aus corporate debt.
3. Opex	4.3%		
Unexplained change in revenue = 2.8% decrease			

Source: NERA analysis.

Table B.5 Primary drivers of Ausgrid's Transmission P_0, ($June 2009)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 46.8% revenue increase			
1. Capex 2004/05 - 2008/09 $402m ($'Jun09) 2009/10 – 2013/14 $1,184m ($'Jun09) Increase $783m, ie, 195%	29.9%	a) Asset renewal/replacement - Increased from $158m to $573m - 53% of total increase in real capex	
		b) Reliability and quality of service enhancement - Increased from $0m to $157m - 20% of total increase in real capex	
		c) Augmentation to meet peak demand growth - Increased from $177m to $327m - 19% of total increase in real capex	
2. WACC	16.0%	Real post-tax WACC increased from 6.48% to 7.59%. Increase in the DRP contributes 131 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A- 10yr Aus corporate debt.
3. Opex	4.9%		
Unexplained change in revenue = 3.7% increase			

Source: NERA analysis.

B.2. Queensland

Table B.6 Primary drivers of ENERGEX's P_0, ($June 2010)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 42.6% revenue increase			
1. WACC	18.9%	Real Post tax WACC increased from 5.74% to 7.25%. Increase in the DRP contributes 132 basis points to the WACC The change in Gamma added $189.5m (ie, which in itself leads to a P0 price increase by 3.7%)	**No change in the benchmark**, ie, QCA assumed BBB+ 10yr Aus corporate debt Result of decision of the Tribunal to lower the gamma from 0.5 to 0.25.
2. Capex <u>2005/06 - 2009/10</u> $3.22b <u>2010/11 – 2014/15</u> $5.80b <u>Increase</u> $2.59b, ie, 80%	8.8%	a) Augmentation to meet peak demand growth - Increased from $1.63b to $2.76b - 44% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $275m to $1.09b - 31% of total increase in real capex	
3. Opex	2.7%		
Unexplained change in revenue = 14.2% increase			

Source: NERA analysis.

Table B.7 Primary drivers of Ergon Energy's P_0, ($June 2010)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 47.5% revenue increase			
1. WACC	17.8%	Real Post tax WACC increased from 5.74% to 7.25%. Increase in the DRP contributes 132 basis points to the WACC The change in Gamma added $131.5m (ie, which in itself leads to a P0 price increase by 2.8%)	**No change in the benchmark**, ie, QCA assumed BBB+ 10yr Aus corporate debt Result of decision of the Tribunal to lower the gamma from 0.5 to 0.25.
2. Opex	7.9%	Base year opex.	Ergon noted that the "AER Decision effectively removed all step changes".
3. Capex <u>2005/06 - 2009/10</u> $3.29b <u>2010/11 – 2014/15</u> $5.11b <u>Increase</u> $1.82b, ie, 55%	7.2%	a) Augmentation to meet peak demand growth - Increased from $859m to $1.54b - 37% of total increase in real capex	i. Ergon stated "Significantly overspent this category in previous period and anticipated continuing level af activity in regional Qld"
		b) New customer connections (excluding customer contributions) - Increased from $858m to $1.40b - 30% of total increase in real capex	i. Ergon stated "Significantly overspent this category in previous period and anticipated continuing level af activity in regional Qld"
Unexplained change in revenue = 16.2% increase			

Source: NERA analysis.

B.3. South Australia

Table B.8 Primary drivers of ETSA Utilities' P_0, ($June 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 36.4% price increase			
1. Capex <u>2005/06 - 2009/10</u> $767m <u>2010/11 – 2014/15</u> $1,590m <u>Increase</u> $824m, ie, 107%	10.6%	a) Augmentation to meet peak demand growth - Increased from $204m to $615m - 50% of total increase in real capex	i. Electricity Transmission Code changes ii. Continuing peak demand growth iii. Network utilisation approaching maximum prudent limits
		b) Non-network assets - Increased from $173m to $331m - 19% of total increase in real capex	i. Renewal of major IT systems, IT support for increased network capital program, new Network Operations Centre. ii. Existing property maintenance and upgrades. To meet changing field requirements, relocation of existing depots, establishment of new offices and depots. iii. New vehicles for increases employee numbers and capital program, legislative required updates to vehicles. iv. Plant and Tools associated with new vehicles, building plant.

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
2. WACC	10.4%	Real Post tax WACC increased from 6.50% to 7.29%. Increase in the DRP contributes 86 basis points to the WACC. The change in Gamma added $162.2m in additional revenue (ie, which in itself leads to a P0 price increase by 5.8%)	**No change in the benchmark**, ie, ESCOSA assumed BBB+ 10yr Aus corporate debt Result of decision of the Tribunal to lower the gamma from 0.5 to 0.25.
3. Opex	10.0%	a) Base year - 77% of total allowed	
		b) Step changes - 20% of total allowed	i. Feed In Tariffs $39m, Asset Inspections $26m, IT support $28m, Property costs & Land Tax $21m, Insurance premiums and support $21m, Superannuation contributions $12m, Network Maintenance & Planning $14m. ii. Operating support for significant increase in capex. Note that under ETSA Utilities Cost Allocation Method (CAM), all corporate overheads are expensed.
Unexplained change in prices = 7.8% increase			

Source: NERA analysis.

Table B.9 Primary drivers of ElectraNet's P_0, ($June 2008)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 33.9% revenue increase			
1. WACC	14.1%	Real Post tax WACC increased from 6.23% to 8.07%. Increase in the DRP contributes 137 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A 10yr Aus corporate debt.
2. Capex 2003/04- 2007/08 $412m 2008/09– 2012/13 $626m Increase $214m, ie, 52%	8.5%	a) Augmentation to meet peak demand growth - Increased from $51m to $131m - 38% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $190m to $236m - 22% of total increase in real capex	
		c) New customer connections (excluding customer contributions) - Increased from $0m to $44m - 21% of total increase in real capex	
3. Opex	2.7%		
Unexplained change in revenue = 10.3% increase			

Source: NERA analysis.

B.4. Australian Capital Territory

Table B.10 Primary drivers of ActewAGL's P_0, ($2008/09)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 22.7% price increase			
1. Opex	18.2%	Feed-in tariff and UNFT tax contributed $47.9 million ($08/09) and $10.8 million ($08/09) to the increase respectively. Specifically, step changes* contributed approximately 14% to the total allowed opex in the current regulatory period.	
2. Capex 2004/05- 2008/09 $147m 2009/10– 2013/14 $275m Increase $129m, ie, 88%	4.6%	a) Augmentation to meet peak demand growth - Increased from $9m to $75m - 50% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $70m to $95m - 19% of total increase in real capex	
3. WACC	-0.6% (New allowance would decrease prices – ie, real opex has fallen between the current period and the last)	Real Post tax WACC increased from 6.36% to 6.37%. Increase in the DRP contributes 140 basis points to the WACC.	**No change in the benchmark**, ie, the ICRC assumed BBB+ 10yr Aus corporate debt.
Unexplained change in prices = 0.7% increase			

Source: NERA analysis.

** We understand from ActewAGL that there was only one major step change included in the final decision which was outside of ActewAGL's control, being the Feed-in Tariff (FiT).*

B.5. Tasmania

Table B.11 Primary drivers of Transend's P_0, ($June 2009)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 32.5% revenue increase			
1. Opex	10.6%	The allowance provided by the ACCC for the 2004-09 regulatory period was unsustainably low.	
2. Capex 2004/05- 2008/09 $334m 2009/10– 2013/14 $606m Increase $273m, ie, 82%	9.1%	a) New customer connections , to meet customer demand:[137] - Increased from $5.7m to $110m - 40% of total increase in real capex	
		b) Augmentation to meet demand growth and reliability standards - Increased from $127m to $233m - 39% of total increase in real capex	
3. WACC	7.5%	Real Post tax WACC increased from 6.55% to 7.58%. Increase in the DRP contributes 125 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A 5.5yr Aus corporate debt.
Unexplained change in revenue = 5.9% increase			

Source: NERA analysis.

[137] Note that Transend the comparison of new connection capex is not strictly on a like-for-like basis because: Transend has converted from an "as commissioned" recognition of capex to an "as incurred" approach; and connections expenditure was not separately identified within the 'development' category in the previous period.

B.6. Victoria

Table B.12 Primary drivers of CitiPower's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 1.4% price increase			
1. WACC	4.9%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
2. Opex	1.2%	a) Base year opex - 84% of total allowed opex	
		b) Step changes - 11% of total allowed opex	i. Electricity Safety (Electric Line Clearance) Regulations
3. Capex 2006- 2010 $605m 2011– 2015 $768m Increase $163m, ie, 27%	1.2%	a) New customer connections (excluding customer contributions) - Increased from $165m to $224m - 67% of total increase in real capex*	
		b) Augmentation to meet peak demand growth - Increased from $217m to $268m - 58% of total increase in real capex*	
Unexplained change in prices = 5.5% decrease			

*Source: NERA analysis. * Note: the two percentages presented here exceed 100% as there was a real decrease in capex allowed for 'asset renewal/replacement'.*

Table B.13 Primary drivers of Powercor's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 6.3% price increase			
1. WACC	4.1%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
2. Opex	3.7%	a) Base year opex - 84% of total allowed opex	
		b) Step changes - 11% of total allowed opex	i. Electricity Safety (Electric Line Clearance) Regulations
3. Capex <u>2006- 2010</u> $886m <u>2011– 2015</u> $1,324m <u>Increase</u> $438m, ie, 49%	3.4%	a) New customer connections (excluding customer contributions) - Increased from $164m to $428m - 81% of total increase in real capex*	
		b) Environmental, safety and statutory obligations (excluding reliability) - Increased from $92m to $231m - 43% of total increase in real capex*	
Unexplained change in prices = 4.4% decrease			

Source: NERA analysis

** Note: the two percentages presented here exceed 100% as there was a real decrease in capex allowed for 'asset renewal/replacement'.*

Table B.14 Primary drivers of Jemena's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 11% price increase			
1. WACC	6.6%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
2. Capex <u>2006- 2010</u> $333m <u>2011– 2015</u> $434m <u>Increase</u> $101m, ie, 30%	1.6%	a) Environmental, safety and statutory obligations (excluding reliability) - Increased from $23.6m to $80.7m - 57% of total increase in real capex*	i. Bushfire Mitigation (Poles Top Structures, Poles and Conductor Replacement) ii. Public Safety - Neutral Screen Service Replacement iii. Electric Line Clearance Regulation
		b) Augmentation to meet peak demand growth - Increased from $58m to $99m - 40% of total increase in real capex*	
3. Opex	-3.6% (New allowance would decrease prices – ie, real opex has fallen between the current period and the last)	a) Base year opex - 84% of total allowed opex	
		b) Step changes - 13% of total allowed opex	i. Changes to Electrical Safety (Management) Regulations incl Process Compliance is the single biggest contributor
Unexplained change in prices = 6.8% increase			

Source: NERA analysis.

Table B.15 Primary drivers of SP AusNet's Distribution P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 19.2% price increase			
1. Opex	9.2%	a) Base year opex - 73% of total allowed opex	
		b) Step changes - 22% of total allowed opex	i. New vegatation management regulations associated with bushfire mitigation
2. Capex <u>2006- 2010</u> $670m <u>2011– 2015</u> $1,417m <u>Increase</u> $747m, ie, 111%	6.8%	a) Augmentation to meet peak demand growth - Increased from $114m to $389m - 42% of total increase in real capex	
		b) New customer connections (excluding customer contributions) - Increased from $234m to $432m - 30% of total increase in real capex	
		c) Non-network assets - Increased from $33m to $168m - 20% of total increase in real capex	i. Change in IT and vehicles from opex (leasing) to capex (ownership)
3. WACC	6.3%	Real Post tax WACC increased from 5.97% to 7.13% Increase in the DRP contributes 153 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
Unexplained change in prices = 2.3% increase			

Source: NERA analysis.

Table B.16 Primary drivers of United Energy's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 5.6% price increase			
1. Capex 2006- 2010 $624m 2011– 2015 $753m Increase $129m, ie, 21%	4.2%	a) Environmental, safety and statutory obligations - Increased from $90m to $213m - 96% of total increase in real capex*	
		b) Augmentation to meet peak demand growth - Increased from $111m to $181m - 55% of total increase in real capex*	
2. WACC	3.8%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
3. Opex	2.8%	a) Base year opex - 86% of total allowed opex	
		b) Step changes - 10% of total allowed opex	
Unexplained change in prices = 4.9% decrease			

Source: NERA analysis.

** Note: the two percentages presented here exceed 100% as there was a real decrease in capex allowed for 'asset renewal/replacement'.*

Table B.17 Primary drivers of SP AusNet's Transmission P0, ($June 2008)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 15.3% revenue increase			
1. WACC	3.2%	Real Post tax WACC increased from 6.20% to 7.17%. Increase in the DRP contributes 55 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A 5yr Aus corporate debt.
2. Capex 2003/04- 2007/08 $398m 2008/09– 2013/14 $771m Increase $373m, ie, 94%	3.1%	a) Asset renewal/replacement - Increased from $339m to $522m - 49% of total increase in real capex	
		b) Environmental, safety and statutory obligations (excluding reliability) - Increased from $0m to $158m - 42% of total increase in real capex	
3. Opex	1.1%		
Unexplained change in revenue = 5.5% increase			

Source: NERA analysis.

Appendix C. Real Cost Escalation Factors

The following real cost escalation factors have been developed for the ENA by SKM, for use in the current analysis.

Table C.1 Annual real cost escalators developed by SKM

Category	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Distribution Capex program	1.009	1.086	1.053	1.029	1.015	0.967	0.939	1.007	0.979	1.010	1.013	1.023	1.001	1.032	1.026
Distribution Opex program	1.010	1.029	1.021	1.017	0.999	1.010	0.991	1.004	1.001	1.008	1.013	1.017	1.011	1.020	1.021
Transmission Capex program	1.014	1.094	1.049	1.037	1.024	0.970	0.932	1.011	0.983	1.010	1.012	1.021	1.001	1.032	1.027
Transmission Opex program	1.010	1.029	1.021	1.017	0.999	1.010	0.991	1.004	1.001	1.008	1.013	1.017	1.011	1.020	1.021

Note: Escalation factors are year-on-year for the year ending in June of each year.

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Attachment B

NERA Economic Consulting Report

Attachment B – NERA Economic Consulting Report – Rising Electricity Prices and Network Productivity: a Critique

NERA
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Rising Electricity Prices and Network Productivity: a Critique

A report for the Energy Networks Association

16 April 2012

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Contents

Executive Summary

This report has been prepared by NERA Economic Consulting (NERA) at the request of the Energy Networks Association. It provides a critique of the following two reports, prepared by Bruce Mountain on behalf of the Energy Users Association of Australia:

- *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors* 'Mountain (2011)' published in May 2011;[1] and
- *Electricity Prices in Australia: an International Comparison* 'Mountain (2012)' published in March 2012.[2]

Following a review of the expenditure allowances of distribution network service providers (DNSPs), Mountain (2011) concludes that regulatory failure and government ownership are the major causes of recent increases in the price of electricity distribution, rather than the oft cited need for investment to replace aging assets and meet the requirements of rising peak demand. On this basis, Mountain makes a number of recommendations that, the paper argues, would raise productivity in this sector.

Our assessment of the analysis undertaken in Mountain strongly suggests that it provides an insufficient basis for such conclusions. Failure to consider the many legitimate reasons for variances in costs and a reliance on inappropriate comparisons has resulted in Mountain drawing unsubstantiated conclusions about the relative efficiency of DNSPs. Mountain's focus on ownership as the key distinction between DNSPs omits consideration of state-specific cost drivers. Identification of actual cost drivers is further hampered by Mountain's use of state averages rather than reviewing data on a DNSP specific basis.

Mountain begins by comparing revenue, capital expenditure (capex) and the value of the regulatory asset base (RAB) per connection within each state, on a weighted average basis. The paper notes that growth in each of these ratios has been substantially higher for DNSPs in Queensland and New South Wales as opposed to South Australia and Victoria. Mountain consequently concludes that the financial performance of government-owned DNSPs, being those in Queensland and New South Wales, is relatively poor compared to that of the privately-owned DNSPs, being those in South Australia and Victoria.

A comparison of these ratios is ill-suited to making conclusions regarding the relative efficiency of DNSPs. There are numerous reasons, besides relative efficiency, why DNSPs may have different levels of operating expenditure (opex) and capex, and different RAB values per connection. These may include service quality standards, past expenditure decisions and the nature of the network, such as the mix between industrial and residential connections, network length, customer density, peak and average demand levels, the split between transmission and distribution networks.

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1 Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*, May 2011.

2 Mountain, B.R., *Electricity Prices in Australia: an International Comparison*, CME, March 2012.

Furthermore, the use of averages for each state masks variations in costs between firms *within* each state. Such a loss of information makes it difficult to draw any robust conclusions about the true causes of cost differences.

Mountain (2011) then develops a composite scale variable (CSV) to assess the relative efficiency of DNSPs. In essence, this analysis assumes that customer numbers and network length are the only drivers of DNSP costs. In our opinion, this is not a reasonable assumption, since it overlooks the many other potential sources of cost differentials. His approach therefore does not provide a sound basis upon which to draw any conclusions about the relative efficiency of businesses.

There are likewise many shortcomings contained in Mountain's comparison of the costs of NEM distributors and the costs of businesses located in Great Britain. First, there are a number of intrinsic difficulties associated with making international comparisons that can reduce the explanatory power of such analyses, including:

- the use of different exchange rates can greatly affect the results;
- government policies can affect prices; and
- regulatory and accounting differences between jurisdictions can mean that costs are not directly comparable, ie, one may not be comparing 'like with like'.

Second, there are many reasons for prices differing across countries that have nothing to do with the relative efficiency of the businesses in each location. For example:

- there may be many differences in the characteristics of the networks being considered such as the line length and the level and growth in peak demand;
- there may be distortions in the current prices due to past regulatory decisions; and
- there may be jurisdictional differences in the cost of inputs, eg, cost of capital, labour and materials costs may vary significantly across geographies.

Mountain reviews a number of potential cost drivers that may have been responsible for recent price increases in Australia. In our view, a number of conspicuous deficiencies in Mountain's analysis mean that one cannot reasonably conclude that government ownership and the regulatory framework are the key drivers of price increases. In particular, Mountain:

- dismisses rising peak demand as a driver of investment by reference to the growth in *historic aggregate* and *average* demand. These metrics are not relevant, since networks must be configured to meet *anticipated peak* demand, not past average demand. It is clear that peak demand is expected to grow considerably in some states and this will naturally precipitate additional investment that will need to be remunerated through price increases;
- rules out the need to replace aging assets as a driver of investment by considering the average effective remaining life of assets. However, this measure is not informative of the value of assets that need replacing at any one time since DNSPs' assets will have different age profiles;
- dismisses claims that there is an element of 'catch-up' in investment due to past levels of under-investment, largely on the basis of reports suggesting the DNSPs could become more efficient and reduce their operating costs, which is of highly questionable relevance.

In our opinion, the analysis provided in the NERA report, *Analysis of Key Drivers of Network Price Changes* provides a significantly better basis for determining the actual cost drivers that have led to the recent price increases.[3] By way of brief summary, that report concludes that the key drivers of price changes have been:

- increases in the allowed WACC;
- increases in the capex allowance; and
- increases in the allowed opex.

Moreover, in each case the reasons for the increase were external drivers such as an increase in the measured debt risk premium, ageing assets and new statutory obligations such as feed-in tariffs, rather than reflecting a shortcoming in the Rules.

Mountain's second paper for the EUAA, *Electricity Prices in Australia: An International Comparison,* was not submitted to the AEMC as part of the review of the NER. However, the timing of its release makes it likely the paper will receive some attention in the course of this review.

Mountain (2012) provides an international comparison of electricity retail prices. On the basis of this comparison, Mountain concludes that Australian prices are high and rising when compared to those in other countries. Because the report considers *retail* prices – and only for household customers – rather than the costs of DNSPs, it has little if any relevance for the AEMC process.

Moreover, the paper exhibits a number of shortcomings. The choice of the exchange rate has a significant impact on the results. Mountain has largely focused on market exchange rate based comparisons, and it is on the basis of these prices that Mountain draws his conclusions. However, the purchasing power parity based comparisons that Mountain presents show a substantially narrower gap between retail prices in Australia and overseas. In fact, on this basis, Mountain finds that Australian prices are actually lower than those in Japan and the EU. The overseas data is also older, further reducing the relevance of the comparison. Finally, we note that Mountain's conclusions are inconsistent with those reached by a number of other commentators.[4]

It must be borne in mind that many factors may result in differences in retail prices including government policies, how electricity is generated and geographical and meteorological factors. In short, even if Mountain's analysis did establish that retail prices in Australia were higher (which it does not), there are many potential explanations unrelated to efficiency.

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3 NERA, *Analysis of Key Drivers of Network Price Changes,* April 2012.

4 See section 4 below.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) at the request of the Energy Networks Association (ENA). The ENA has asked us to review and comment on the following two reports, prepared by Bruce Mountain on behalf of the Energy Users Association of Australia (EUAA):

- *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors* (hereafter referred to as 'Mountain (2011)') published in May 2011;[5] and
- *Electricity Prices in Australia: an International Comparison* (hereafter referred to as 'Mountain (2012)') published in March 2012.[6]

Mountain (2011) seeks to identify the cause of the significant recent cost increases for distribution network service providers (DNSPs) throughout Australia. The EUAA relies on the material in Mountain (2011) to support the following points in its submission to the Australian Energy Market Commission (AEMC) on the rule change proposals for the economic regulation of network services:[7]

> '[r]ising demand, ageing assets and historic underinvestment has been blamed, mainly by NSPs but also at times by regulators and governments, for significantly higher expenditure and prices. But closer analysis suggests that these are not adequate explanations… the explanation for rising expenditure is not exogenous factors such as ageing assets and demand growth but rather *the differing efficiency of the distributors in managing these factors*'[8] (emphasis added)
>
> 'Comparative benchmarking shows that the efficiency of government-owned distributors has declined significantly relative to their privately owned peers over the course of the three regulatory control periods that have applied to these distributors, so that government-owned distributors are now on average half as efficient as their privately owned peers.'[9]

The AEMC's Directions Paper notes that the analysis and findings of cost inefficiency presented in Mountain (2011) have not been rebutted.

Mountain (2012) provides a comparison of international retail electricity prices and concludes that Australian electricity prices have risen sharply in the recent past and are now higher than those in Japan, the EU, the US and Canada. This report has not been submitted to the AEMC as part of the review of the NER and it has not been relied upon in submissions to

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5 Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*, May 2011.

6 Mountain, B.R., *Electricity Prices in Australia: an International Comparison*, CME, March 2012.

7 EUAA, *Submission to the Australian Energy Market Commission on the Rule Change Proposals for the Economic Regulation of Network Services*, December 2011.

8 EUAA, *Submission to the Australian Energy Market Commission on the Rule Change Proposals for the Economic Regulation of Network Services*, December 2011, pp.i-ii.

9 EUAA, *Submission to the Australian Energy Market Commission on the Rule Change Proposals for the Economic Regulation of Network Services*, December 2011, p.ii.

the AEMC. However, it may receive some attention in the AEMC's review given the timing of its publication.

The ENA has therefore commissioned NERA to review the two papers prepared by Mountain and to opine upon the robustness of the analysis and conclusions.

The remainder of our report is structured as follows:

- section two provides our review of section three in Mountain (2011) which presents comparisons of revenues, expenditure, service levels and efficiency of DNSPs in Victoria, New South Wales, Queensland and South Australia;
- section three contains our analysis of section four in Mountain (2011) which discusses a number of potential reasons for the differences in revenues, expenditure, service levels and efficiency of DNSPs; and
- section four reviews Mountain's more recent paper (Mountain (2012)), which compares retail electricity prices in various countries.

2. Mountain (2011): Outcomes

This section provides our critique of section three of Mountain (2011). We use the same heading titles as that report and review each sub-section in turn. We proceed by first summarising Mountain's key findings, then reviewing the analysis underpinning those findings and their attendant robustness.

Section three of Mountain (2011) purports to assess the relative performance of DNSPs and to determine whether or not there is 'an efficiency issue that merits attention'.[10] The section presents comparisons of revenues, expenditure, service levels and Mountain's measure of efficiency. On the basis of these comparisons, Mountain concludes that:

- revenues collected by government owned DNSPs in New South Wales and Queensland have grown far faster than the privately owned DNSPs in Victoria and South Australia;[11]
- the main reason for this difference is increased returns on and of assets;[12]
- the regulated asset base is growing much more quickly for government owned distributors because their capitalised expenditure is around four times higher per connection compared to their privately owned peers;[13] and
- government owned distributors are, on average, half as efficient as the privately owned distributors.[14]

2.1. Comparison of revenue, expenditure, assets and service performance

2.1.1. Summary of Mountain's analysis

Mountain (2011) shows that the average allowed revenue per connection has been significantly greater for DNSPs in New South Wales and Queensland than those in South Australia and Victoria since around 2009.[15] The timing of this increase correlates with the beginning of the current regulatory period.

DNSPs in New South Wales and Queensland are government owned. Their counterparts in South Australia and Victoria are privately owned. In other words, since 2010, average allowed revenue per connection has been significantly greater in government owned DNSPs – in both metropolitan and country areas.

Mountain (2011) finds that government owned DNSPs have had consistently higher opex per connection since 2002 but there has been no recent significant change in the gap between the

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10 Mountain (2011), p.25.

11 Mountain (2011), p.v.

12 Mountain (2011), p.v.

13 Mountain (2011), p.vi.

14 Mountain (2011), p.vi.

15 Mountain (2011), p.25.

government and privately owned DNSPs. He contends that the reason for the change in allowed revenue per connection around 2010 is the proportionately greater increase in the capitalised expenditure per connection of government owned DNSPs.

Mountain attempts to assess whether lower revenues in some states are associated with a 'degradation in service performance'.[16] This is assessed by examining the average level of service interruption frequency and duration of interruption for each state from 2001 to 2009. Mountain concludes that the average performance of privately owned DNSPs in relation to both metrics is superior to their government owned counterparts.

2.1.2. Review

Mountain (2011) draws two principal conclusions from the analysis described above:[17]

- that a comparison of revenues and expenditures shows some businesses have performed better than others; and
- that the 'superior financial performance' of South Australian and Victorian DNSPs has not been at the expense of poorer service performance.

Mountain (2011) has demonstrated that costs per customer have increased more rapidly in NSW and Queensland compared to South Australia and Victoria, and that the most significant cause of this rapid increase has been related to capex rather than opex. However, in our opinion, this does not constitute a sufficient basis from which to draw any reasonably inferences or conclusions about the comparative performance of DNSPs.

Although Mountain has adjusted the costs of each firm to account for differences in customer bases (by using average revenue and capex per connection), this is not sufficient to produce a comparable metric capable of revealing any information about relative efficiency. The reason for this is that there are a multitude of reasons why DNSPs may have different levels of opex and capex per connection. Some differences may relate to factors DNSPs can control, and others may not. For example, cost differences may arise due to:

- service quality standards;
- past expenditure decisions;
- differences in the boundaries between transmission and distribution companies in the various states;
- the different accounting methodologies that DNSPs may employ;
- the mix between industrial and residential connections;
- network length;
- customer density;
- labour costs;
- the proportion of the network that is underground;

[16] Mountain (2011), p.28.

[17] Mountain (2011), p 28.

- peak and average demand levels;
- the occurrence of floods, fires and other natural phenomena that can damage distribution wires;
- the climate and terrain;
- transformer capacity; and
- transmission losses.

It is likely that all these factors affect the data underpinning the conclusions set out in in Mountain (2011).[18] It follows that those conclusions cannot be relied upon, absent a more fulsome analysis that takes account of these alternative potential explanations for differences across firms. Furthermore the use of an average revenue figure for each state masks variations in costs between firms in the same state, and represents another reason why the analysis cannot be relied upon to reveal any meaningful information about the efficiency performance of businesses.

Mountain reviews the difference in quality of service provided by DNSPs to assess whether the lower cost of service in Victoria and South Australia has led to poorer service standards. On the basis of the *averages from 2001 to 2009* of the System Average Interruption Frequency and the System Average Interruption Duration Indices, Mountain concludes that service performance in Victoria and South Australia has been *slightly better* than in New South Wales and Queensland. There are a number of problems with this analysis.

First, the relevance of the data itself is questionable. Mountain (2011) is largely concerned with price increases that have occurred *since 2009*, yet his data corresponds to an *earlier period*.

Second, Mountain uses nine year averages, rather than presenting the time series on an annual basis. For example, consideration of the underlying series over this period shows an increase in the total length of interruptions in Victoria, where expenditure per connection has been low, and a decrease in the number and total length of interruptions in New South Wales, where expenditure per connection has been high.[19]

Notwithstanding this, any consideration of measures of quality is fraught with complications and Mountain's simple comparison fails to account for many of the quality dimensions that are important to network users or the numerous factors that influence service levels but are beyond the control of DNSPs, eg, electrical storms, flooding and fires. In a recent report, the AER explained that:[20]

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18 Given the large number of potential causes of different costs of electricity distribution, it is not surprising that electricity prices vary across states and countries. For example, there is a wide variation in EU electricity prices, see Mountain (2012), p.11.

19 The average number of interruptions (and their total length) in New South Wales for the first half of the decade was 1.94 (238 minutes) per year and for the second half of the decade it was 1.74 (186 minutes) per year. In Victoria, average number of interruptions (and their total length) for the first half of the decade was 1.98 (152 minutes) per year and for the second half of the decade it was 1.98 (203 minutes) per year. Source: AER, *State of the Energy Market*, December 2011, p.68.

20 AER, *State of the Energy Market*, December 2011, p.68.

> '[a] number of issues limit the validity of comparing reliability data across jurisdictions. In particular, the data rely on the accuracy of the businesses' information systems, which may vary considerably. Geographic conditions and historical investment also differ across the networks.'

The AER has also stated that 'Queensland experiences significant variations in performance partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other NEM jurisdictions.'[21] It added that that 'an assessment of network performance should normalise data to exclude interruption sources beyond the network's reasonable control.'[22]

In our opinion, Mountain (2011)'s service quality analysis provides an insufficient basis to support any conclusions relating expenditure levels to service performance. In particular, it is incapable of enabling any conclusion to be reached as to whether the cost increases in Queensland and New South Wales *since 2009* have been inefficient.

In sum, the analysis contained in the 'Comparison of revenue, expenditure, assets and service performance' section of Mountain (2011) cannot be relied upon to reach any conclusions about the relative efficiency of DNSPs. Mountain himself acknowledges this to a limited degree, when he states in the following section:[23]

> '[t]he results presented in this section so far are the ratios of the revenues or expenditures relative to customer numbers. These ratios are strongly suggestive of differences in efficiency. But it is not possible to draw categorical conclusions from this on the relative efficiency of the distributors.'

Put simply, because Mountain does not consider the many other potential, legitimate reasons for cost differences across firms, he risks drawing erroneous inferences and conclusions.

2.2. Efficiency benchmarking using statistical regressions

2.2.1. Summary of Mountain's analysis

Mountain sets out an explanation of his efficiency benchmarking analysis in Appendix A. His methodology involves the derivation of a 'composite scale variable' (CSV) for each firm, which he then uses to arrive at an estimate of the expenditure levels each firm should theoretically be incurring. Those hypothetical levels are then compared to each firm's actual expenditures to ascertain whether they are over or under spending.

Mountain then ranks the firms according to their performance against the hypothetical cost benchmarks. His 'efficiency frontier' is defined such that 25 per cent of firms are considered to be 'efficient' and the remaining 75 are deemed to be 'inefficient'.

21 AER, *State of the Energy Market*, December 2011, pp.68-69.

22 AER, *State of the Energy Market*, December 2011, p.68.

23 Mountain (2011), p.30.

2.2.2. Review

Although benchmarking can be a useful tool, if it is done improperly or interpreted without sufficient care, it can lead to erroneous conclusions. In particular, Mountain himself emphasises the importance of undertaking benchmarking analysis using accepted econometric or statistical techniques. In our opinion, the analysis he has undertaken has not met this standard.

In essence, the regression analysis undertaken as part of Mountain's CSV methodology has done no more than consider the extent to which customer numbers and network length explain costs. While this is a step forward from the use of average costs per connection, as used in the previous section, it still fails to account for a great number of the other variables discussed in section **Error! Reference source not found.** that can also influence DNSP's costs. It follows that the analysis described above is again an insufficient basis to reach any conclusions about the relative efficiency of firms.

Appendix A indicates that Mountain realised other variables would be likely to impact costs but statistical limitations precluded their inclusion in his analysis. In particular, although Mountain considered including 'energy distributed' and 'peak demand' in his analysis he chose not to. He reasoned that due to the close relationship between customer numbers, energy distributed and peak demand meant that including only customer numbers would suffice.

We disagree. Omitting potentially relevant variables in this manner will often create more problems than it solves.[24] It is interesting to note that Mountain and Littlechild (2010) included three variables in their equivalent CSV exercise. In any event, as we noted above, even if Mountain had included all four variables in the CSV analysis, this still would not have been sufficient to account for all of the potentially relevant cost drivers.

Furthermore, even if one could reasonably consider customer numbers and network length as being the only relevant variables driving a company's costs (a proposition we consider entirely unreasonable), it is not clear whether Mountain's analysis of the CSV would be appropriate given that:

- he does not adjust for the 'lumpy' nature of capex, ie, under his analysis, a firm may appear inefficient if it has recently invested in a large capital project with a long life, even though this investment may be prudent and efficient;
- Mountain has assumed that expenditure should be a linear combination of customer numbers and network length, which leads to the improbable result that there would be no economies of scale as a network increases in size. There does not appear to be any justification for such a restriction;
- the intercept of the regression has been constrained to zero by Mountain, implying that a DNSP without customers or network length would have zero costs. This assumes that the DNSP would have no fixed costs, and consequently fails to take into account factors such as the cost of a management team and the cost of infrastructure that is unrelated to scale. This constraint appears to have been chosen to avoid a negative intercept, which would

[24] O'Brien, R. M., *A Caution Regarding Rules of Thumb for Variance Inflation Factors*, Quality & Quantity, 2007.

imply negative fixed costs for a DNSP. In our view, the fact that Mountain's model returns a negative intercept without this constraint strongly suggests that the model has been misspecified;

- Mountain does not report any statistical tests, or even the relative weights of the variables in the CSV. Such test results are important in assessing the robustness and explanatory power of the regression, and consequently the accuracy and reliability of its results;
- it is not clear whether the costs considered are opex or total expenditure (ie, the sum of opex and capex) since appendix A seems to use the terms opex and total expenditure interchangeably. It follows that:
  - if total expenditure has been used, it is not clear why Mountain developed the CSV since the first and second steps of the analysis could usefully be compressed into one step without any effect on the results; or
  - on the other hand, if Mountain has used opex as the explanatory variable, then his analysis sheds even less light on relative performance as Mountain has suggested it is capex rather than opex that is the main contributor to the difference in performance between DNSPs.

For a benchmarking exercise to be informative it should, as far as possible, control for all differences in operating conditions between firms. However, Mountain's analysis controls only for customer numbers and network length. There are many other factors that could, and should, be taken into account. Furthermore, the paper provides no statistical evidence to indicate how much of the DNSPs' costs are explained by these variables. It would therefore be imprudent to accept the conclusions that Mountain draws from his analysis.

Ofgem has used a CSV in the past to assess the efficiency of electricity distributors.[25] However, it no longer relies on the use of a CSV in its measurement of efficiency. In its most recent electricity distribution price review for the years 2010 to 2015, it used a much more granular and robust analysis that included a number of different models, methods and estimation techniques. These included, without limitation:

- the use of linear and non-linear models;
- the use a variety of techniques to ensure outcomes are not skewed by any one particular approach;[26]
- inclusion of a variety of variables to explain cost differences between DNSPs;
- the comparison of a subset of DNSPs' costs since only some of the costs are comparable;[27]
- a series of statistical tests to assess the robustness and explanatory power of the models;[28]
- a wide range of different cost drivers in the models; and[29]

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[25] See the following review of Ofgem's use of a CSV: CEPA, *Background to Work on Assessing Efficiency for the 2005 Distribution Price Control Review*, September 2003.

[26] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.42.

[27] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.39.

[28] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009 – Appendix 5, pp.18-21.

- adjustments to costs to make them comparable.[30]

Mountain (2011) has not applied any of the techniques or methods listed above. It follows that the analysis is significantly less robust than might otherwise be the case if the best available techniques had been employed. This is further demonstrated by the fact that using the simple CSV approach can lead to substantially different results than if a more detailed analysis was undertaken. For example, Ofgem has shown that the detailed analysis it conducted for its most recent electricity distribution price review led to different results to those under the CSV approach that it had previously employed.[31]

The results from even a well specified benchmarking exercise would need to be interpreted with care before concluding that one DNSP was necessarily inefficient compared to others. Rather than indicating 'inefficiency', relatively high expenditure may be due to the specific circumstances of a DNSP that the model was unable to account for. Analysis similar to that undertaken in the NERA report, *Analysis of Key Drivers of Network Price Changes,* would be important in informing such an assessment.[32]

2.3. Comparing NEM distributors to those in Great Britain

In Section 3.3, Mountain provides a comparison of allowed revenues per connection for DNSPs in New South Wales, Queensland, South Australia and Victoria with those of Great Britain. The values for Great Britain are taken from Mountain and Littlechild (2010).[33] The comparison indicates that:

- the revenues per connection have been much lower in Great Britain than in Australia; and
- revenues per connection in South Australia, Queensland and New South Wales have been increasing more rapidly since around 2009.

Conducting international comparisons is not as simple as it might appear, and there are a number of reasons why caution should be employed when considering Mountain's analysis. This is explicitly acknowledged in Mountain and Littlechild (2010) which states:[34]

> '[i]t is hoped that our preliminary findings will encourage further and more rigorous analysis in order to shed more light on these important issues.'

First, one must be careful when converting prices from one currency to another since the exchange rate can have a substantial effect on relative electricity prices. The Australian dollar has risen from around 0.4 pounds to the dollar at the beginning of 2007, to 0.68 pounds to the dollar in early 2012. This means that the price of electricity will appear to be over 50 per cent

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[29] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.43.

[30] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.44.

[31] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009 – Appendix 5, p.15.

[32] NERA, *Analysis of Key Drivers of Network Price Changes,* April 2012.

[33] Mountain, B., Littlechild, S., *Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria*, Energy Policy, September 2010 (hereafter, 'Mountain and Littlechild (2010)').

[34] Mountain and Littlechild (2010), p.5771.

higher in Australia relative to the UK in early 2012 compared to 2007, purely on the basis of movements in the exchange rate.

We note that Mountain has used *market* exchange rates to conduct his analysis, which is not standard practice when comparing costs across countries. The more generally accepted approach is to use a measure of purchasing power parity (PPP), which adjusts for the 'buying power' of the currency in each country. The OECD estimated that the PPP exchange rate was one pound to 2.35 Australian dollars in 2011.[35,36] This means that the same basket of goods could be purchased for one pound in Britain or $2.35 in Australia. This contrasts to Mountain's use of a market exchange rate of $1.59 to the pound. If one were to use the PPP exchange rate rather than the market exchange rate, it would result in estimates of the revenues for Great Britain that are 37 per cent higher than those presented by Mountain from 2011.

A second complication arising in international comparisons is the need to ensure that the data really is comparable. In this regard, it is particularly important to consider whether the cost information from DNSPs in Great Britain and Australia cover the same categories, and are compiled using equivalent accounting methods. It is unclear whether this is the case; for instance, we understand that in 1999 Ofgem cut back the scope of operating expenses attributed to the distribution businesses.[37] In addition, it is not evident that the split between transmission, distribution and retail functions is the same across the two jurisdictions. If the Australian DNSPs include different categories of costs, or have different accounting methods, these differences should be taken into account when making any comparisons with the distribution businesses in Great Britain.

In addition to this, comparisons of prices over a short time period (relative to asset lives) should be treated with caution. There may be factors that distort prices within a given time period, such as regulatory decisions that affect prices in a way that is inconsistent with the underlying costs of the DNSP. For instance, we understand that in England and Wales, the regulatory asset value of pre-vesting assets was set equal to the market value of the company at privatisation. These asset values are substantially lower than the modern equivalent asset value of the assets. We also understand that the depreciation of the pre-vesting regulatory asset values was accelerated. The life of pre-vesting assets was only 11-16 years from 1990. Depreciation on pre-vesting assets was therefore coming to an end during the 2000-05 period for some companies, and the 2005-10 period for others. Accelerated depreciation reduced accounting costs but led to cash flow problems such that Ofgem accelerated the depreciation on post-vesting assets as well. This reduced revenues for 2000-2010 due to the rapid fall in asset values. Costs and revenues for DNSPs are now rising due to an increase in capital expenditure required to maintain or replace existing assets. Indeed, Ofgem's final proposals of December 2009 show that a substantial increase in revenue is required for all but one company.[38]

35 Source: PPP for GDP, OECD 2011.

36 See Tables 1.2 and 1.12, *2008 PPP Benchmark results*, OECD. Available at < http://www.oecd-ilibrary.org/statistics>.

37 Ofgem, *Distribution Price Control Review: Draft proposals*, August 1999, Tables 1-14.

38 Ofgem, *Electricity Distribution Price Control Review Final Proposals*, Ref 144/09, December 2009, pp.33-34.

We also understand that between 2000 and 2005, British companies deferred necessary capital expenditure by extending the asset lives of their existing assets. As a result of this, several companies have increased their capital expenditure for asset replacement since 2005, and it is expected that forecast investment will continue to grow strongly.[39] However, this will not be fully reflected in the comparison provided in Mountain (2011) since the capital expenditure is likely to affect revenues over a longer period than the next few years.

There are also many legitimate reasons for the differences in allowed revenues per connection in Britain and Australia. These reasons are largely similar to those discussed in relation to the cost differences between DNSPs in different states. For this reason, international comparisons usually try to compare areas that have as few differences as possible. For example, Ofgem only included the north eastern states of the US in its comparison of DNSPs in the US and UK since those states are thought to have similar weather conditions to the UK.[40] Mountain (2011) does not appear to have done this, which raises further questions over the reliability of his results given that weather patterns are very different in Australia and the UK.

Differences in the level of peak demand and average network length between Britain and Australia may also assist in explaining why allowed revenues per connection differ between these jurisdictions. For example:

- the average network length per 1,000 customers is 84km in New South Wales, 61km in Victoria and 27km in the UK;[41] and
- peak demand in Australia, driven by heavy demand for air-conditioning, is substantially higher than in the UK. The average peak demand in the UK is around 2.1MW per 1000 customers, whereas in New South Wales it is 3.53, and in Victoria 3.28.[42]

Compared with the UK, electricity networks in New South Wales therefore have more than three times as much network length per customer, and must serve about 70 per cent more peak demand per customer. These factors alone would explain a substantially higher cost per customer in New South Wales than in Great Britain, even if everything else was equal.

It is also likely that there will be significant differences in the cost of inputs between the UK and Australia. Mountain and Littlechild (2010) dismiss differences in input costs as a factor in explaining variations in revenues per connection. For example, they explain that:

[39] Ofgem, *Electricity Distribution Price Control Review: Final Proposals - Allowed revenue*, Cost assessment appendix, 146a/09, December 2009, Table 9 – General reinforcement – Final Baseline, Table 12 Final Baseline Fault Levels, Table 13 Final Baseline – Asset Replacement.

[40] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper*, May 2009 – Appendix 5, p.16.

[41] AER, *State of the Energy Market*, 2011, page 56; and Ofgem, *Electricity Distribution Annual Report* 2010-11, Supporting Data File entitled "ED_Annual_Report_2010_11_data_public.xlsm", available at <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=702&refer=Networks/ElecDist/PriceCntrls/DPCR5>.

[42] AER, State of the Energy Market, 2011, p.56; Nationalgrid website, <http://www.nationalgrid.com/uk/Electricity/MajorProjects/EnergyChallenge.htm>; and Ofgem, Electricity Distribution Annual Report 2010-11, Supporting Data File entitled "ED_Annual_Report_2010_11_data_public.xlsm", see <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=702&refer=Networks/ElecDist/PriceCntrls/DPCR5>.

> 'most capital items employed by distributors (transformers, switchgear, lines and cables) are internationally traded and therefore, if effectively procured, should cost much the same in New South Wales and GB.'[43]

However, this ignores the transport cost for these capital items, importation and other regulatory charges, economies of scale from selling more items in Europe and potentially the greater buyer power of European firms who may purchase more than Australian firms. Furthermore, the assets are long lived and exchange rate movements will distort the comparisons between revenues that are, at least in part, based on historic cost information.

The differences in costs between the UK and Australia may also be due to legitimate difference in the rates of returns between the countries. Mountain and Littlechild (2010) noted that the single biggest driver of the cost divergence was the rate of return regulators in Australia allowed DNSPs compared to regulators in the UK. This is the case and is related to a number of legitimate reasons rather than an inherent inability of the regulator to constrain prices. This is discussed in greater detail in section 3.6.

In conclusion, the results of the comparison in Mountain (2011) could be caused by a range of factors, including exchange rate movements, differences in cost categories and accounting practices, variations in the definition of 'distribution', short term variations in expenditure and the many differences between distribution networks in the UK and Australia. Therefore, it is not clear what conclusions, if any, can be drawn from the comparisons in Mountain (2011).

[43] Mountain and Littlechild (2010) p.5773.

3. Mountain (2011): Possible Explanations for Rising Prices and Declining Productivity

In the preceding section, we explained that Mountain concluded DNSP costs have been rising rapidly in Queensland and New South Wales and that these increases have largely been due to capital expenditures, rather than operating costs. Regulators and DNSPs have put forward a number of reasons to explain these increases. In this section, Mountain considers a number of these explanations in turn.

In our opinion, the main problems with the analysis in this section of Mountain (2011) are that:

- each explanation is considered individually rather than collectively. In practice, many variables are likely to have an effect on the level of expenditure of DNSPs at the same time. A multiple regression analysis would be preferable as it would allow a number of variables to have an effect on expenditure simultaneously; and
- the analysis of each explanation is insufficient and inconclusive.

3.1. Rising peak demand

Mountain shows that the average annual growth rate in demand has recently been greatest in Victoria, whilst being slightly lower in New South Wales and Queensland and much lower in South Australia. Mountain finds that growth related expenditure (per connection or per MW of additional demand) is higher in New South Wales and Queensland than in the other two states.

Thus Mountain concludes that '[d]emand related expenditure has been poorly correlated to demand growth'[44] and states:[45]

> 'growth-related expenditure allowed by the AER has been four times higher per connection for government owned distributors in New South Wales and Queensland than for privately owned distributors in Victoria and South Australia. This suggests the main issue seems to be an inefficient response to demand growth by government owned distributors, sanctioned by the regulator.'

The relevant consideration for DNSPs when considering investment needs is *future peak demand*. It is peak, and not average demand, that is the key determinant of how a distribution network is constructed or upgraded. However, Mountain presents *historic* information on *average demand per customer* and *total demand*. This information has no obvious bearing on the increases in capital expenditure experienced from 2009.

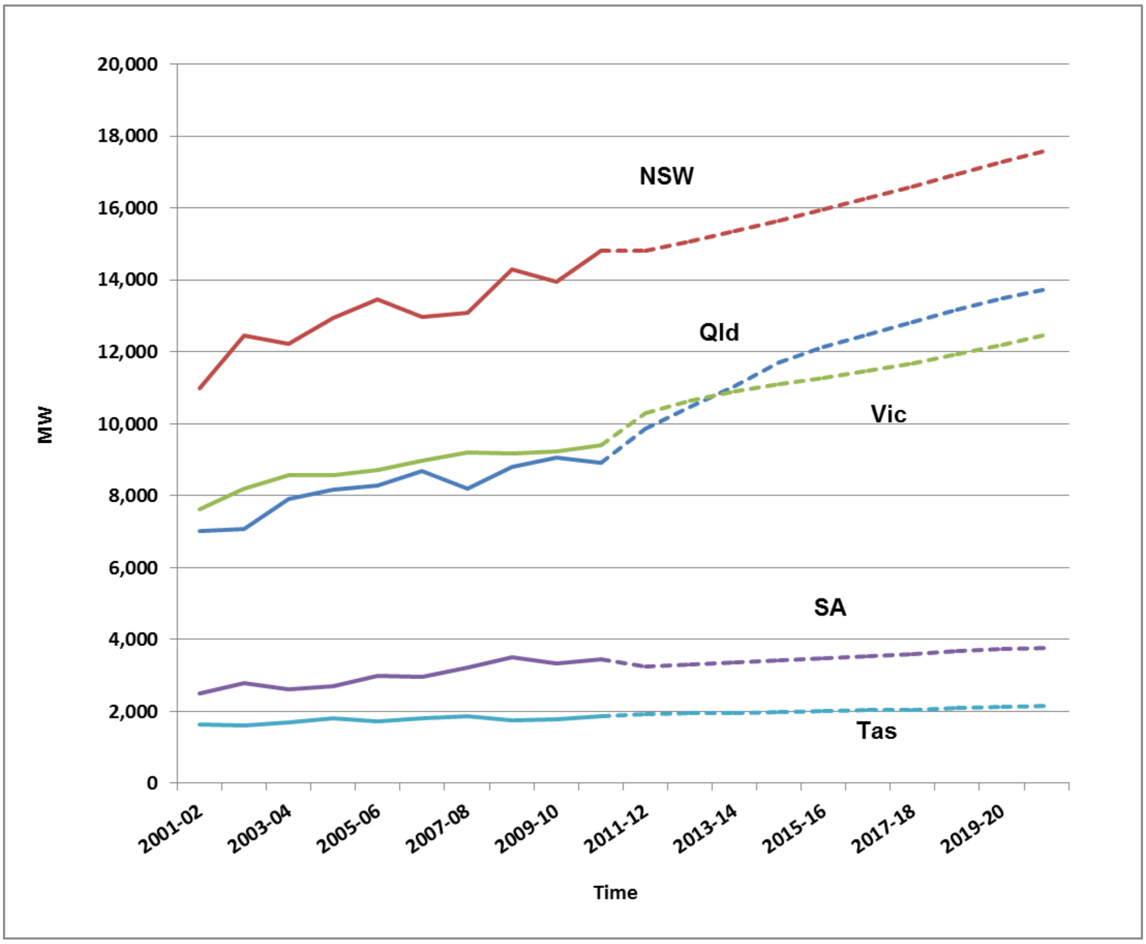
Figure 3.1 below shows how the level of total peak demand has changed, and is expected to change, across New South Wales, Queensland, Victoria, South Australia and Tasmania.

[44] Mountain (2011), p.57.

[45] Mountain (2011), p.vi.

Maximum demand is expected to be highest and growing most rapidly in New South Wales and Queensland from around 2012/2013.

Figure 3.1
Growth in maximum demand in the NEM



Source: AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.11.

The AER has said that: '[o]verall maximum demand for energy in Queensland is expected to grow at around twice the rate of growth of customer numbers over the period 2010–2015.'[46] Thus substantial investment may be needed to meet this higher peak demand. Similarly, the AER has explained that peak demand is expected to grow in New South Wales and that this will require investment expenditure:

> '[m]aximum demand growth in New South Wales is projected to increase by between 2.7 per cent and 3.5 per cent a year between 2010/11 and 2013/14 (depending on the distribution area). Demand growth is expected to be highest in Endeavour Energy's distribution area, due to higher and more sustained peak temperatures in south and western Sydney, and the high uptake of air conditioners across its network. This trend is resulting in an overall shift towards higher maximum demand in summer compared

46 AER, *Queensland distribution determination 2010-11 to 2014-15*, Final decision, p.vi.

> to winter in New South Wales. As a result, significant increases in capital works are required to ensure this projected growth in maximum demand can be met.'[47]

Our sister report[48] also demonstrates that, for some DNSPs, rising peak demand explains a substantial part of the recent increases in capex. For example, augmentation to meet peak demand growth contributed 24 per cent of the total increase in the real capex allowance for Ausgrid and 37 per cent for Essential Energy – both of which are in New South Wales.[49]

Even so, there are reasons why peak-demand related investment may not be perfectly correlated with anticipated peak demand growth at any point in time. For example there may have been capacity to deal with rising peak demand in some of these networks without needing higher levels of investment. This will depend on past investments and the nature of the network. It may also be the case that the cost of investment differs across states for legitimate reasons. This could be due to, for example, different standards, topology, levels of underground cabling, customer density, location of new customers relative to existing customers, wages and the cost of land. Therefore, a consideration of the level of peak demand growth on its own is insufficient to understand what expenditure may be needed as a result.

In summary, we do not consider the analysis undertaken in Mountain (2011) provides sufficient basis to discredit the claim that growth in peak demand has been a key driver of capex.

3.2. Ageing assets

Mountain finds that the per connection allowances to replace aging assets has been nearly four times higher in New South Wales and Queensland compared to Victoria and South Australia.[50] Mountain also finds that the DNSPs in New South Wales and Queensland had, on average, longer remaining asset lives than those in South Australia and Victoria. The average remaining asset life was estimated by weighting the remaining asset life in each asset class by the value of the assets in that class. On this basis, Mountain suggests that government-owned DNSPs have been given inappropriately high allowances by the AER.

The average remaining life of a DNSP's assets is only of limited relevance because the key driver of investment will be the extent to which assets are retired at any point in time. A comparison of average asset lives will not provide information on the extent to which assets need replacing if the age profile of assets differs between DNSPs.

For example, two networks will have the same average remaining asset life if one has all of its assets with a remaining life of 20 years and the other has half of its assets with a remaining life of one year and the other half with a remaining life of thirty nine years. However, the implied investment profile for these two DNSPs will look vastly different. Mountain argues

47 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.31.

48 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

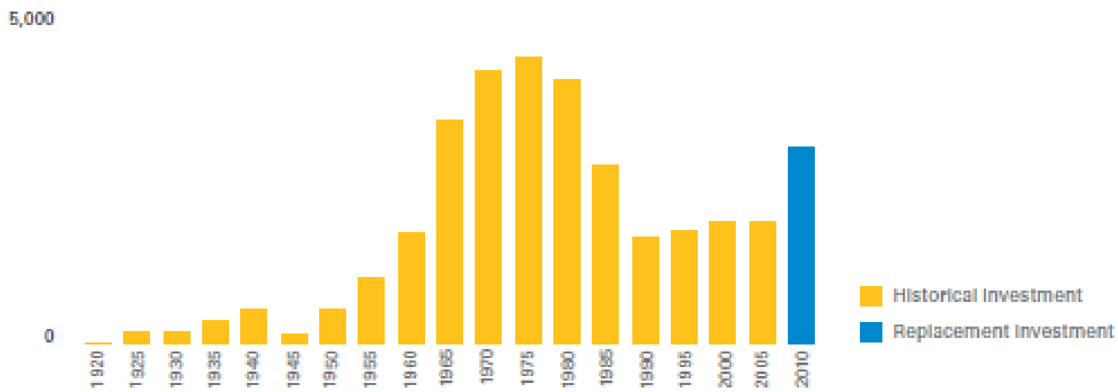
49 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

50 It is unclear over what period Mountain makes this comparison. We assume that it is a comparison of recent data.

that there is 'no reason to believe that such an asymmetry exists'.[51] On the contrary, Figures 3.2 to 3.4 suggest that the age profile of DNSPs are far from identical, for example:

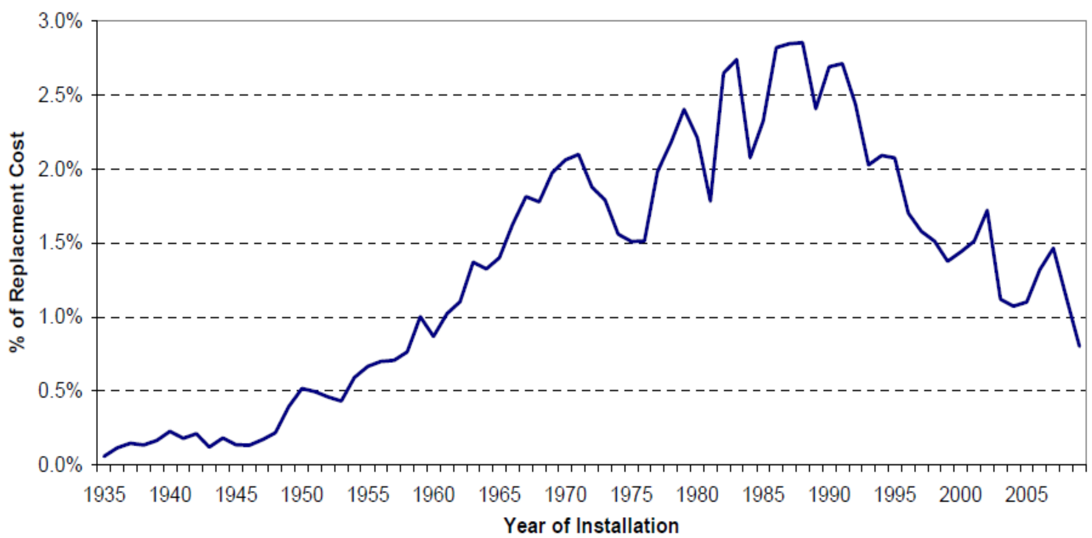
- Ausgrid has a peak in the value of assets built in the 1970's and early 1980s followed by a significant fall in the late 1980's;
- SP Ausnet has a peak in the late 1980s and early 1990s with a significant drop in the late 1970s; and
- Jemena has roughly the same value of assets installed from the late 1960's to the late 1990's.

Figure 3.2
Replacement cost for electricity distribution assets for Ausgrid (FY09 $m real)



Source: EnergyAustralia, *Regulatory Proposal*, June 2008, p.5.

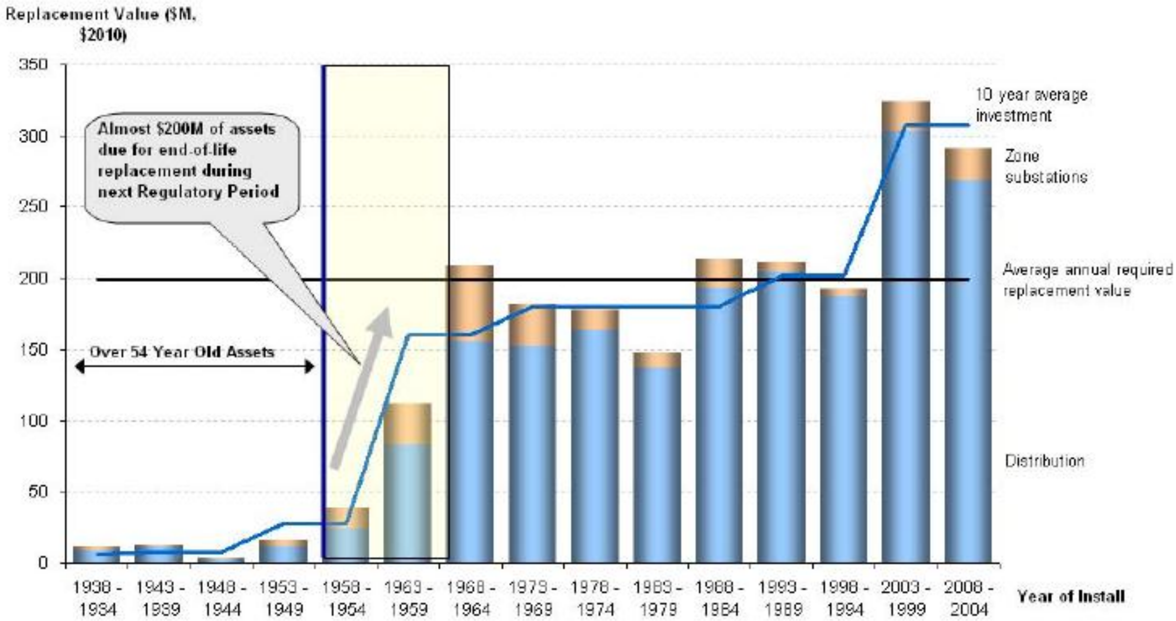
Figure 3.3
Network Age profile, SP AusNet



Source: *SPI Electricity, Electricity Distribution Price Review 2011-2015, Regulatory Proposal*, November 2009, p.45.

51 Mountain (2011), p.74.

Figure 3.4
Asset replacement value by installation year for Jemena



Source: Jemena, *Regulatory Proposal 2011-15*, November 2009, p.95.

Since the age profile of electricity distribution assets vary across DNSPs, the average age of assets is not the appropriate way to calculate the value of assets that need replacing.

In contrast to Mountain's conclusion, the AEMC has identified ageing assets as one of the main drivers of the rising costs of distribution services in NSW.[52] NERA analysis has also shown that replacing ageing assets has been a significant cause of the recent increase in capex for some DNSPs.[53] For example, asset renewal and replacement contributed 56 per cent of the total increase in the real capex allowance for Ausgrid in the current regulatory period.[54]

3.3. Historic underinvestment

In considering the issue of historic underinvestment, Mountain looks at two reports:

- Pierce, J., Price, D., Rose, D., *The Performance of the NSW Electricity Supply Industry*, Reserve Bank of Australia, 1995; and
- Independent Panel, *Detailed Report of the Independent Panel: Electricity Distribution and Service Delivery for the 21st Century*, July 2004.

The first report found that 'between 1982 and 1994 average annual capital productivity growth of New South Wales distributors was just 0.2 per cent per annum, and that New South Wales distributors could achieve 20-30 per cent reduction in operating costs through

52 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*, November 2011, p.21.

53 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

54 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

efficiency gains'.[55] On this basis, Mountain concludes that 'there is no evidence to suggest that the higher expenditure by New South Wales distributors since 2000, and particularly over the current regulatory period is needed to make up for historic underinvestment. In fact the available evidence suggests exactly the opposite is the case.'[56]

The relevance of potential efficiency gains that may have been available up to thirty years ago is highly questionable. That average annual capital productivity growth was low *between 1982 and 1994* tells us nothing about the need for investment *since 2009* to make up for past under-investment. Even if this information were more recent, capital productivity growth and opex inefficiencies would tell us little about the need for catch-up investment.

The second report cited by Mountain claims there had been underinvestment in Queensland's electricity distribution. However, Mountain discounted this report mainly due to questions about the methodological robustness of the measure of overall average capacity utilisation and an argument that the finding that Energex should adopt higher planning standards did not show that Energex had failed to meet the required standards.

Mountain does not provide a compelling case for discounting the argument that a certain amount of current investment is required to make up for past levels of under-investment.

3.4. Higher network planning standards

Queensland and New South Wales have recently set higher standards for DNSPs, which have argued that meeting these standards has required considerable additional capex. Mountain concurs that this is likely to have been the case and that this could explain part of the difference between the expenditures of New South Wales and Queensland with other States.[57]

However, Mountain also notes that this improvement in standards has not had a measureable effect in terms of the quality of the service. We note that improvements in network planning standards may not create substantial and immediate increases in observable measures of quality for a number of reasons:

- it takes some time for investment to be carried out and a new asset to become operational;
- higher standards will only relate to new work and this is a small proportion of a total network;
- there is a substantial amount of volatility in the interruption statistics used by Mountain to measure quality; and
- improvements in quality may well result from higher standards without them being observable in current statistics on interruptions. For example, the higher standards may protect against a disruption in electricity distribution in a major flood. However, if the major flood never occurs, the standards will not lead to any measureable change in the number or length of electricity interruptions..

[55] Mountain (2011), p.39.

[56] Mountain (2011), p.42.

[57] Mountain (2011), p.42.

The AEMC has identified higher reliability standards as one of the 'main drivers of the rising costs of distribution services in NSW'.[58] The AEMC has explained this as follows:

> '[a]dditional capital expenditure over the current regulatory determination is also needed to meet the higher reliability standards for New South Wales distributors. In 2005, the New South Wales Minister for Energy amended the licence conditions of New South Wales distributors to require them to comply with new design, reliability, and performance requirements by 2012/13. This has contributed to further anticipated capital works by the distribution businesses, particularly Essential Energy, to meet these standards within the required timeframes. The AER has advised that reliability and quality of service enhancements comprise around 10 per cent of the total capital expenditure by New South Wales distributors over the current regulatory period.'[59]

In our opinion, higher network standards are likely to have resulted in higher expenditure by some DNSPs. However, the analysis in Mountain (2011) does not allow for an estimate of the scale of this effect.

3.5. Asset valuation

Mountain shows that the values of the regulatory asset base (RAB) per customer are higher in New South Wales and Queensland than in South Australia and Victoria. In addition this difference is increasing over time.

Mountain suggests three possible reasons for this:

- the networks in New South Wales and Queensland are newer;
- there may be different definitions of transmission and distribution in different states; or
- governments are likely to have a greater incentive to increase the RAB as they receive the dividend from the profit.

Mountain notes that government owned distributors value their easements at significantly higher levels than the DNSPs in Victoria and South Australia. He concludes that 'the fact that government owned distributors are valued so much higher per kilometre of line than privately owned distributors suggests that ownership has affected asset valuation.'[60]

As discussed in the sections above, capex has been higher in New South Wales and Queensland than in South Australia and Victoria. Furthermore, there are a number of legitimate reasons for this, none of which have been credibly refuted by Mountain. This will be, at least in part, driving the differences in the RAB, as noted by Mountain.

It is also unclear whether Mountain (2011) has taken into account the recent increase in the value of easements in South Australia from $8m to $123m.[61] This increase means that one of

58 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*, November 2011, p.21.

59 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.31.

60 Mountain (2011), p.44.

61 Application by ETSA Utilities [2010] ACompT 5 (13 October 2010), available at <http://www.austlii.edu.au/au/cases/cth/ACompT/2010/5.html>.

the states in which distributors are not government owned has very substantial easement values.

Furthermore, Mountain has not considered a range of other factors that will results in higher RABs in Queensland and New South Wales compared to South Australia and Victoria. These factors have been discussed in the sections above and include such factors as the need for these networks to be constructed so as to meet higher levels of peak demand.

For similar reasons and because of the complexities of making international comparisons, we do not consider the comparison with RABs in Great Britain to be helpful. We therefore see no evidence to draw a conclusion that the nature of ownership has been a key determinant in establishing the RAB.

3.6. Allowed rates of return

The AER has set a higher allowed rate of return than the jurisdictional regulators had previously set. Mountain points out that the main reason for this is an increase in the debt risk premium. Mountain also notes that Mountain and Littlechild (2010) found that the cost of capital allowed for DNSPs was significantly higher in Australia than the UK.

There has been a significant increase in the debt risk premium since the global financial crisis and this has been a major contributor to higher prices. However, it would be premature to assume that this was due to a failing in the regulatory regime. This issue is considered in greater detail in two complementary reports.[62]

Specifically, for DNSPs, the benchmark now adopted by AER (BBB+, 10 year) is either the same as or a slightly higher grade of debt than that adopted by the previous jurisdictional regulators at the time of the earlier regulatory decisions. This implies that, absent any change in market conditions, the debt risk premium would have been the same or lower for the DNSPs. For the TNSPs the AER benchmark (again, BBB+, 10 year) has been modestly reduced from that applied in the previous regulatory period (ie, A, 10 year). However the change in the benchmark was determined by the AER as appropriate in the 2009 SORI.[63] In neither case does the change in the debt risk premium reflect a shortcoming with the Rules.

3.7. Customer density

Mountain considers whether customer density may explain the difference in costs between Australian distributors and those in the UK. He concludes that it does not.

However, Mountain's assessment is not compelling for a number of reasons. Most importantly, in comparing customer densities and costs, Mountain does not adjust for other factors. In other words, his assessment is not based on 'all other things being equal'. Mountain provides an example of a DNSP with a lower customer density that has lower costs than two other DNSPs with a higher customer density. However, it still may be the case that lower customer density increases costs because the difference between the DNSPs' costs in the example may be driven by other factors.

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62 NERA, *Analysis of Key Drivers of Network Price Changes,* April 2012 and NERA/PWC, *Debt Risk Premium – Response to the AEMC Direction Paper,* April 2012.

63 AER, *Statement of the Revised WACC parameters (transmission),* May 2009, p.6.

Furthermore, by considering simple correlations between customer density and expenditure levels, Mountain only assesses whether there is a linear relationship between network density and the cost of electricity distribution. It is likely that the relationship will be more complex than this. For example:

- the cost of distribution per customer in a dense urban environment can be very high since the distribution wires may need to be underground and access to buildings may be necessary;
- where density is fairly low, for example just outside a city, customers may be supplied with single wire earth return lines over open ground that travel fairly short distances and the cost of distribution may be less than in an urban environment;
- where customer density is very low indeed, distribution may be by means of a single wire earth return line but the distance between each customer would push up cost of distribution per customer; and furthermore
- two areas with the same customer density but different clustering patterns may have different average costs. For example, a rural area with a small village surrounded by relatively empty countryside may have lower average costs than a rural area with a number of households spread throughout the countryside.

Therefore, customer density may have a complex and non-linear effect on the cost of electricity distribution. The analysis in Mountain (2011) is not able to detect such a relationship. Hence, in our opinion, the analysis presented in Mountain does not provide a compelling argument for discounting customer density as an explanation of cost differences.

3.8. Ownership

After discounting some explanations for recent price increases, Mountain concludes that Government ownership is a key determinant of higher prices, giving the following reasons:

- private firms can be expected to be more interested in maximising profit and therefore will be more responsive to regulatory incentives that reward reducing expenditure;
- a government that is also an investor will be more receptive to regulation that increases dividends than a government that is not an investor; and
- the target rates of return in the public sector are lower than the private sector such that government-owned DNSPs will have an incentive to invest more in capital expenditure than private businesses.

As discussed in the sections above, we do not believe Mountain has provided compelling reasons to discount legitimate explanations for cost differences considered above. Furthermore, Mountain has not undertaken any analysis to determine the extent to which many state-specific factors will have a justifiable impact on cost differences.

Evidence that DNSPs in NSW and Queensland (which are state owned) have higher costs than those in Victoria and South Australia (which are publicly owned) does not prove that ownership is the cause of this difference.

The explanations of the incentives of government-owned businesses are also not compelling, especially given the separation between the states and the regulator. In our opinion, Mountain does not have sufficient evidence to draw the conclusion that differences in ownership are the cause of the variations in expenditure.

3.9. Regulatory design and conduct

After discounting the various other explanations for recent price increases, Mountain concludes that the regulatory framework must also be a key determinant of higher prices. As discussed above, Mountain has not provided compelling arguments for discounting these other explanations of the price increases. Therefore, there is no basis upon which to conclude that regulation must be responsible for the recent price increases. However, we have addressed each of Mountain's concerns, briefly, in the interests of completeness.

Mountain raises three concerns about the existing regulatory framework:

- the 'propose-respond' doctrine puts an onus of proof on the AER to justify any amendments to the DNSPs price forecasts and this puts the regulator at a considerable and unfair disadvantage;[64]
- the asymmetry of the appeal process unduly favours DNSPs and allows 'cherry picking'; and
- the AER has not made as much use of benchmarking as it could.

Mountain's portrayal of the current regulatory framework is somewhat inaccurate. In particular, there is no 'onus of proof' in the current process for setting expenditure allowances. No forecast can ever be 'proved' and this concept simply does not fit with the task to be undertaken. In assessing DNSPs submissions, the regulator must accept a forecast only if ***it is satisfied*** that the forecast reasonably reflects efficient costs, the costs a prudent operator in the circumstances of the NSP would require. This issue is considered in further detail in *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*.[65].

Mountain's interpretation of the approach in Great Britain is also not entirely accurate. Ofgem also gives considerable weight to the submissions of the regulated businesses and is required to provide reasons for its decisions under Section 42 of the *Utilities Act 2000*. Although on the surface the UK regulatory regime may appear to provide Ofgem with considerable discretion that is not available to the AER, in practice the extent to which Ofgem may exercise unguided discretion is heavily constrained by the ability of NSPs to reject price control proposals and initiate a wide ranging merits review process.

Furthermore, we do not consider it the case that DNSPs have 'strong incentives to make ambit claims'.[66] This has been discussed in a recent joint report for the ENA which concluded that the AER has not been constrained to accept inflated total expenditure forecasts proposed by the NSPs.[67] For example, the AER has not accepted NSP's proposed total expenditure forecasts in any of its determinations.

64 Mountain (2011), p.51.

65 NERA/PWC/Gilbert+Tobin, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011.

66 Mountain (2011), p.54.

67 NERA/PWC/Gilbert+Tobin, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011.

In regard to the appeal process and the potential for cherry picking, there is no evidence presented as to how or why this may currently be occurring. It is very costly to take an appeal to court and therefore unlikely a DNSP will appeal unless some part of a decision is substantially detrimental to it. If the regulator knows this and has an incentive to attempt to reduce prices then it may be able to set prices below the median reasonable level. This is in direct contrast to Mountain's contention that the appeal mechanism probably also encourages 'the AER to err on the side of the distributors in their regulatory decisions'.[68]

Mountain's point in relation to benchmarking appears to be a criticism of the AER's implementation of the regulatory framework rather than the framework itself. However, it is noteworthy that the AER undertook a number of benchmarking exercises in its recent determination of the prices for electricity in New South Wales.[69] For example, it undertook a benchmarking exercise for Ausgrid's controllable opex.[70]

68 Mountain (2011), p.55.

69 AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, April 2009.

70 AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, April 2009, p.174.

4. Mountain (2012)

Mountain's second paper for the EUAA, *Electricity Prices in Australia: An International Comparison,* was not submitted to the AEMC as part of the review of the NER. However, the timing of its release makes it likely the paper will receive some attention in the course of this review.

Mountain (2012) provides an international comparison of electricity retail prices. On the basis of this comparison, Mountain concludes that Australian prices are high and rising when compared to those in other countries.

We have three main comments in relation to this report:

- the report is of limited relevance to the purposes at hand, so while it can be considered interesting it is not directly applicable;
- making international comparisons is complex and other commentators have arrived at quite different conclusions regarding Australia's retail electricity prices; and
- international comparisons must be interpreted with care as there will be many factors driving price differences.

4.1. Relevance of Mountain (2012)

Mountain has not claimed this report is relevant to the rule change review and the report has not been submitted as part of this review. The report's limited relevance stems from two factors.

First, this is a comparison of *retail* electricity prices whereas the review is concerned with transmission and distribution costs. Without separating the effects of retail and generation costs it is impossible to make any conclusions regarding the relative cost of network services.

Second, the household sector used around 25 per cent of all electricity consumed in Australia in 2009-10, with the industrial sector making up the other 75 per cent.[71] Hence, the retail prices are a small part of the total price and may bear no relation to the prices for industrial users.[72]

4.2. Complexity of making international comparisons

Comparing international retail electricity prices for households is not a simple exercise for a number of reasons.

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[71] ABS, *Energy Account*, 2009-10, p.21.

[72] We used a report by the Ontario Power Authority to list countries from lowest to highest industrial and residential electricity price. The Spearman rank correlation coefficient of these two lists was 0.75. Given that this is not a perfect correlation; a country which has higher household electricity prices relative to other countries will not necessarily have higher industrial electricity prices. Source: Ontario Power Authority, *Delivered Electricity Price Comparison*, August 2008.

Retail tariffs tend to be structured with fixed and variable components. In some regions, there are multi-part tariffs, such that the price per unit may increase (or decrease) as consumption increases. For a comparison to be meaningful, it should consider households with similar consumption levels. It is not evident that Mountain has compared such similar households. Indeed, a review of the data Mountain has used suggests this is not the case.

The choice of exchange rate will also play a key role in determining price relativities. Mountain presents information on the basis of two exchange rates: market exchange rates; and PPP. As discussed in section **Error! Reference source not found.**, the PPP is generally thought to provide more meaningful comparisons of costs across countries.[73] Mountain's PPP based comparison significantly narrows the gap between retail prices in Australia versus overseas. In fact, on this basis, Mountain finds that Australian prices are actually lower than those in Japan and the EU.

Care must also be taken when considering prices that are for different regulatory periods. We note that data limitations have meant that the prices in Mountain (2011) are for different periods:

- Australian data are for 12 months *beginning* 1 July 2011;
- the European Union prices are for the first 6 months of 2011;
- the Canadian and Japanese prices are for 2010; and
- the prices for the USA are for the 12 months to November 2011.

Mountain justifies his use of these data on the basis that prices in other countries have not been increasing much. However, we do not find this argument compelling. For example, household electricity prices in the following countries have increased by more than 30 per cent in nominal terms in three and a half years to 2011: Czech Republic, Spain, Latvia, Lithuania, Hungary, Malta, Sweden, Norway and Turkey.[74] According to the UK government, the price of electricity in the UK has increased in real terms by around 57 per cent from 2002 to the third quarter of 2011.[75] This is approximately the same growth as in Australia.

Furthermore, comparisons of Australia's AEMC projections for 2013/14 with the historic prices in other regions must be interpreted even more cautiously as it is highly unlikely prices will remain constant in those regions from 2010 to 2014.

Mountain's results are in contrast to others that have found Australia does not have particularly high electricity prices by international standards. For example:

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[73] The OECD explains that PPP are used to analyse relative price levels across countries <http://epp.eurostat.ec.europa.eu/portal/page/portal/purchasing_power_parities/introduction>, accessed 25 March 2012. The OECD also describes spatial comparisons of price levels as a recommended use of PPP (OECD, 2008 benchmark PPPs measurement and uses, p.2).

[74] Based on NERA analysis of Eurostat data for electricity prices for households from the second half of 2007 to the first half of 2011.

[75] The index of electricity prices in real terms was 90.4 in 2002 and 141.8 in Q3, 2011. Source: Department of Energy and Climate Change, *Quarterly Energy Prices*, December 2011, p.16.

- in 2010 Australian household electricity prices were the 24th cheapest out of 32 OECD countries, according to a 2012 report by the Bureau of Resources and Energy Economics;[76]
- in 2010 Australian residential electricity prices were the 6th most expensive of 11 developed countries, according to a 2010 report by Deutsche Gesellschaft für Technische Zusammenarbeit;[77] and
- in 2007 Australian electricity prices were the 22nd cheapest for industrial customers and 24th cheapest for household customers out of 27 countries, according to a 2008 report by the Ontario Power Authority.[78]

The differences between the results of the studies demonstrate the complexity of making such international comparisons.

4.3. Interpreting international comparisons

Retail electricity prices depend on many factors and trying to draw broad conclusions from international comparisons is almost impossible. For instance, retail prices will, among other things, depend upon:

- the nature of generation;
- tax and regulatory arrangements – although Mountain has taken the pre-tax retail prices, these will not remove the effect of government policies on prices. In Australia for example, the AER has identified the effect of the renewable energy target, feed-in tariff schemes, the carbon tax and various State based policies on electricity prices.[79] There are numerous other policies that will affect the international comparisons in Mountain (2012) including those on planning, regulation, the environment, tariffs, industry subsidies and health and safety;
- the nature of electricity demand, including the level of peak and average demand, the mix of industrial and household customers, population density; and
- the nature of the electricity network, including its age, geographical coverage, service standards.

Drawing conclusions from international comparisons is even more difficult when the information is presented as averages. While it might be possible to consider reasons for price differences when comparing countries on a one-to-one basis, it is much more difficult to make definitive conclusions when comparing Australian prices with, for example, the average price in the EU.

4.4. Conclusion

Mountain (2012) is of limited relevance to the purposes at hand, so while it can be considered interesting it is not directly applicable. This is because it relates to *retail* prices rather than the

[76] Bureau of Resources and Energy Economics, *Energy in Australia 2012*, February 2012, p.41.

[77] Gtz, *Overview of electricity tariffs in G 20 and N11 countries*, 2010.

[78] Ontario Power Authority, *Delivered Electricity Price Comparison*, August 2008.

[79] AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011.

network costs. Furthermore, the study is limited to *household* customers, ignoring the relative prices of industrial customers.

International comparisons are a complex undertaking which necessarily involves considerable discretion, in terms selecting of basket of consumption, the exchange rate and the period of time that the comparison is made. In exercising this discretion, Mountain has emphasised comparisons based on market exchange rates whereas the PPP comparisons are arguably more appropriate. We note that Mountain's own analysis indicates that on a PPP basis Australian retail electricity prices are lower than those in Japan and the average of that in the EU. A further concern we have with the Mountain analysis is his use of older data for jurisdictions other than Australia, that is likely to bias his analysis. We note that other respected commentators have arrived at quite different conclusions regarding Australia's relative retail electricity prices.

It is also important to interpret such international comparisons with care as there will be many legitimate factors driving price differences across jurisdictions.

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Attachment D

Joint Report

NERA Economic Consulting and
PwC

Attachment D – The Debt Risk Premium Benchmark and its Measurement

The Debt Risk Premium Benchmark and its Measurement

A joint report for the
Energy Networks Association

20 April 2012

Project Team

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Contents

1. Introduction

This report has been jointly prepared by Jeff Balchin, Greg Houston and Brendan Quach at the request of the Energy Networks Association (ENA). Its purpose is to address a number of issues relating to the estimation of the debt risk premium (DRP) raised by the Australian Energy Market Commission (AEMC) in its Directions Paper on proposed changes to the National Electricity Rules (NER) and National Gas Rules (NGR) put forward by the Australian Energy Regulator (AER) and the Energy Users Rule Change Committee (EURCC).[1]

In particular, this report addresses two questions raised by the AEMC in its Directions Paper:

Question 30: Is the benchmark DRP approach likely to overstate the prevailing cost of debt, having regard to the suggestion that the overstatement may be a reflection of shorter maturity debt leading to a higher refinancing risk for NSPs? What weight should be placed on the views of market analysis on the ability of stock market listed NSPs to out-perform their cost of debt allowances?

Question 31: What are the pros and cons of the recent approaches taken by IPART and the ERA in estimating the DRP?

As a matter of principle, the cost of debt allowance established by the AER may diverge from the accounting costs of debt experienced by a particular Network Service Provider (NSP) for one or more of three possible reasons. These are that:

- the benchmark established as the reference point for the AER's estimate of the DRP allowance does not reflect the actual financing practices of the NSP in question or the characteristics of the NSP in question may be different to that of the benchmark firm (most importantly, its credit rating may differ from the benchmark);
- there may be errors in the estimation process so that the DRP allowance is not a best estimate of the benchmark (as distinct from whether or not the benchmark itself is appropriate); and/or
- the framework that sets the debt allowance by reference to the current (spot) cost of debt does not reflect the actual cost of debt paid by NSPs.[2]

This report examines the first two possible explanations for a divergence between the regulatory allowances for debt (being the combination of the DRP and the prevailing risk free rate) and the actual cost of debt of NSPs. It also considers the approaches of the ERA and IPART to these same questions, and the extent to which they represent sound alternatives to the AER's methodology.

Further, this report reviews the market analyst reports on publicly listed energy utilities that were referenced in the AEMC's Directions Paper.

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1 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, Directions Paper, 2 March 2012. (Hereafter 'AEMC Directions Paper').

2 Consideration of the merits of adopting a trailing average is addressed in a separate Joint report entitled: *Trailing Average Approaches to the Cost of Debt Allowances,* 16 April 2012.

1.1. Authors and expertise

The authors of this report are: Jeff Balchin, Principal of PwC Australia; Greg Houston, Director of NERA Economic Consulting; and Brendan Quach, Senior Consultant of NERA Economic Consultant. Jeff, Greg and Brendan are all economists with substantial expertise in the economic regulation of network infrastructure services. A short biography for each of Jeff, Greg and Brendan is attached as Appendix B.

The authors also wish to acknowledge the substantial contributions of Victoria Mollard and Sarah Turner, both analysts of NERA Economic Consulting, in the preparation of this report.

1.2. Structure of this report

The remainder of this report is structured as follows:

- Section 2 considers whether the new evidence presented by the AER and EURCC necessarily supports the proposition that the current debt benchmark is no longer an appropriate reference point for estimating the DRP;
- Section 3 reviews the methods by which the AER has estimated the benchmark cost of debt over time and compares this with the approaches of the ERA and IPART; and
- Section 4 reviews the market analyst reports considered by the AEMC and the extent to which they offer support for the suggestion that the cost of debt allowance is a key explanation for listed NSPs trading at a premium to their regulatory asset value.

Appendix A to this report provides a more detailed examination of the analyst reports that the AEMC relies on in the Directions Paper. Appendix B provides a short biography for each of Jeff, Greg and Brendan.

2. The Debt Benchmark

This section considers whether the debt benchmark adopted in the AER's 2009 WACC review continues to be appropriate in light of the more recent evidence put forward to the AEMC by the AER and the EURCC.

The essential thrust of the arguments presented by the AER and EURCC is that NSPs are able to outperform their cost of debt allowances. However, this need not necessarily indicate that the current debt benchmark is incorrect. Indeed, there are reasons other than an incorrectly specified benchmark why NSPs may be outperforming, or appear to be outperforming, their cost of debt allowances, such as:

- the prevailing conditions in the market encourage the firms to shorten or lengthen the term of debt that is issued – although this would bring with it a change to the level of refinancing risk that is borne, and hence may not imply a change to the true cost of debt; and
- the particular circumstances of NSPs, including the existence of parent company support, may give rise to a credit rating (or a positioning within a credit rating band) that is different from that incorporated into the debt benchmark.

We consider each of these in turn below. However, first we discuss the reasons for establishing a cost of debt allowance by reference to a benchmark rather than the actual debt costs of an NSP.

2.1. Benchmark cost of debt

Both the NER[3] and the NGR[4] require that the cost of debt allowance be set by reference to a benchmark rather than the actual cost of debt of a NSP. There are two main benefits to adopting cost of capital benchmarks, ie:

- to provide NSPs with an incentive to adopt efficient debt management practices by allowing them to retain the benefit of outperforming the debt allowance; and
- to shield customers from the cost and risks of poor debt financing decisions.

These principles were referenced by the Australian Competition and Consumer Commission (ACCC), in its original development of the principles of regulation for transmission servicers:[5]

> *The Commission considers, however, that the use of a benchmark rate of return is appropriate as that approach is consistent with the general approach under incentive regulation, whereby firms are permitted to retain any additional value that flows from outperforming predetermined benchmarks (and similarly, are not rewarded for simply achieving the benchmark*

[3] See definition of the DRP in clauses 6.5.2(e) and A6.6.2(e), together with clauses 6.5.3(e)(3) and A6.6.2(j)(3) that set out how principles for reviewing the benchmark credit rating.

[4] See clause 87(2) of the NGR that requires that the rate of return be based on a benchmark levels of efficiency and gearing.

[5] ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 19999, page 76.

> *performance). It is also consistent with the view that the market would not compensate a business with a higher rate of return to meet the cost of sub-optimal debt management, taxation management and financing policies.*

An inevitable consequence of the use of benchmarks in setting cost allowances is that the cost of debt allowance may turn out to be greater or less than the actual cost of debt experienced by any particular NSP. This may occur for a number of reasons, such as:

- the NSP may issue debt with a term that is different from the benchmark which, as discussed in section 2.2 will also have implications for the degree of refinancing risk being taken on by that firm;
- the NSP's actual credit rating may differ from the benchmark, such as the A- credit rating applicable to SP AusNet, as distinct from the benchmark of BBB+; and/or
- a NSP may use different types of debt instruments, such as preferred shares or bank loans.

It follows that the simple observation that a particular firm is, or appears to be, outperforming its cost of debt allowance at a specific point in time is not sufficient to conclude that the allowance is either incorrectly specified or incorrectly measured.

2.2. Term of debt

The first reason that a firm's observed (or apparent) cost of debt may differ to the debt benchmark is if it issues debt of a different term from the benchmark. However, changing the term to maturity of debt changes the refinancing risk borne by an NSP. Refinancing risk arises from the possibility that a business will be unable to borrow to refinance existing debt as it expires, or may only be able to borrow on substantially adverse terms.

The trade-off between the term of debt issued and refinancing risk arises because the yield on shorter term to maturity debt is generally lower than that for longer term debt.[6] Offsetting the additional costs of to a firm of financing itself through long term debt is that, to the extent there is a mismatch between the term of the debt and the expected debt requirement, refinancing risk is lessened. In other words, financing long term assets with long term debt minimises refinancing risk since it reduces the number of times that a firm needs to roll over the debt financing associated with longer term debt.

The existence of refinancing risk was recognised by the AER in the 2009 WACC review where it concluded that:[7]

> *network business will seek to include long term debt in their portfolios so as to mitigate refinancing risk. However, it is clear that the preference for long term debt is balanced with the competing objectives of:*
>
> - *the need to diversify across different maturities, and*
> - *minimising the overall cost of debt.*

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6 Note that debt markets occasionally exhibit a downward sloping yield curve. This occurs when investors expect a fall in future yields of a magnitude sufficient to subsume the premium required by lenders to invest for longer periods.

7 AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Final decision*, May 2009, page 152.

Issuing shorter term debt may reduce a firm's apparent cost of debt; however, it comes at the cost of greater refinancing risk borne by the equity owners of the NSP. This trade-off is recognised in market analyst reports:[8]

> *implicitly the regulated assets are being rewarded for taking the duration mismatch risk*

The implication of this trade-off between the objectives of mitigating refinancing risk by issuing long term debt and the desire to minimise the overall cost of debt is that:

- when the yield on longer term debt is high relative to that on shorter term debt, firms will tend to issue more shorter term debt – however in doing so, those firms are bearing a higher degree of refinancing risk; and
- when market conditions are more benign and the premium for longer term debt is small, firms will tend to issue more longer term debt, and so will bear less refinancing risk.

It follows that the AEMC was correct in its conclusion that firms issuing debt for a shorter term to maturity than established by the benchmark term (and so are borrowing at yields less than the regulatory allowance) are not necessarily overcompensated by the regulatory cost of debt allowance, since this comparisons does not take account of the additional risk that NSPs are bearing.

It is clear that for a period following the onset of the global financial crisis (GFC), corporate bond issues tended to take place at shorter maturities than had previously been the case (or, for a period, not at all). However, this phenomenon does not itself imply that the benchmark maturity should change. Equally, in alternative circumstances where it was observed that bond maturities had extended beyond ten years, it would similarly be unwise to amend the benchmark.

The existence of a relatively stable benchmark has strong merit from the perspective of allowing NSPs to plan and manage their financing and interest rate risk management needs in a stable, predictable regulatory environment. In our opinion, there is no case for the benchmark to 'chase' short or medium term trends in financial market conditions. Rather, it is far preferable to establish a benchmark that is consistent with the long term evidence of debt financing practices, while recognising that short term trends are likely to imply observed variations around it. In our opinion, a decision to shorten the benchmark term to maturity from ten to five years (or, to lengthen it following a run of calm market conditions) should only be taken if there is good reason to believe that there has been a permanent change in the debt financing behaviour of NSPs (or of firms with similarly long-lived assets).

This conclusion is consistent with the advice provided to the AEMC's by its own expert, ie, SFG Consulting, who states:[9]

> *If we observe that the sector is, in fact, consistently able to obtain debt finance on a risk-adjusted basis at below-benchmark rates, then there is evidence that the benchmark is mis-specified. Merely observing that at one point in time the*

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8 Macquarie Equities Research, *DUET Group – Limited RAB growth – at fair value*, 7 November 2011, page 2.

9 SFG Consulting, *Preliminary analysis of rule change proposal: A report for the AEMC*, 27 February 2012 , page 5

sector is borrowing at short-term rates which are below long-term rates does not establish that abnormal returns are being earned on a consistent basis.

.....

If there has been a structural break in the manner in which long-lived assets are financed in the debt market (that is, a paradigm shift to the use of short-term rather than long-term debt) then it is arguable that the benchmark should reflect this structural break. But the proposals do not provide evidence that current debt market conditions do not simply reflect a high risk premium required by lenders for financing long-lived assets.

2.3. Specific features of NSPs

Not all NSPs can be expected to operate in circumstances that perfectly reflect the debt benchmark. For example, it is inevitable that some energy NSPs will have credit ratings that differ from the debt benchmark. These 'specific features' provide one explanation for the fact that some NSPs may experience debt costs that are either below or above, a 'benchmark' level for efficient NSPs.

For example, SP AusNet has a credit rating of an A- rather than the benchmark BBB+ credit rating, although it has a standalone credit rating of BBB+. This distinction is driven by the fact that one of its parent companies is Singapore Power, which has an 'AA-' credit rating, and so rating agencies assume a degree of implicit parental support to SP AusNet.[10] However, it would not be appropriate to take into account any implicit degree of parental support when determining the appropriate benchmark.[11] To do so would involve taking account of matters that amount to a departure from the concept of the representative, benchmark efficient NSP that underpins the NER and NGR.

Furthermore, the actual debt gearing ratio of an NSP may differ from the benchmark NSP, which is assumed to finance 60 per cent of the RAB through debt, while equity finance contributes the remaining 40 per cent. For example, in 2008 the AER indicated that the market debt gearing ratio of Spark was between 45.3 per cent and 57.3 per cent in 2007.[12] In such circumstances, it is reasonable to expect that NSPs choosing to incorporate a higher proportion of equity in their financing structure would subsequently be in position to raise debt at rates less than the assumed benchmark.

2.4. Conclusion

A fundamental property of incentive regulation is that NSPs capable of outperforming a predetermined cost benchmark are able to retain the benefit of that outperformance. Similarly, NSPs bear the cost of underperformance. Setting the cost of debt allowance by reference to a

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10 See Moody's Investor Service notice entitled, *Rating Action: Moody's revises outlook on SP AusNet Group's ratings to stable*, 21 July 2008.

11 We note that SP AusNet also had its A- credit rating at the time the current benchmark credit rating of BBB+ was established by the AER in 2009.

12 AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Draft decision*, December 2008, page 73.

benchmark is consistent with incentive regulation, since firms are provided with incentivises to finance their debt efficiently, and to shield customers from the cost of poor financing decisions by NSPs.

There are a number of reasons why an NSP’s actual or apparent cost of debt may differ from the benchmark allowance. For example, while NSPs seek to mitigate refinancing risk by issuing long term debt, longer term debt generally requires the borrower to pay a premium over shorter term debt. Consequently, efficient NSPs must strike a balance between their need to minimise refinancing risk and the associated premium that must be paid to do so. In market conditions (like those experienced since the onset of the GFC) where the premium for longer term debt is high, firms tend to issue shorter term debt. This would be observed as a fall in the cost of debt; however, shorter debt issues bring greater refinancing risk, and hence need not imply that the true cost of debt (that is, inclusive of the value of refinancing risk) would have fallen.

SFG highlights that that the phenomenon of firms reacting to stressed market conditions by issuing debt on terms that are shorter than average is not sufficient to conclude that the benchmark is no longer appropriate. We concur with this observation. A comprehensive examination of whether there has been a structural break in the financing practices of NSPs would be necessary before concluding that the current benchmark is no longer appropriate.

Furthermore, focusing on a small sample of NSPs may also give a distorted view of the benchmark debt financing arrangements of all NSPs. Observations to date by the AEMC and the AER appear to have focused primarily on three publically listed energy businesses (DUET Group, Spark Infrastructure and SP AusNet), and have not considered whether the specific circumstances of any of these businesses might explain why they have outperformed the benchmark cost of debt.

Notwithstanding our opinion that the new evidence does not invalidate the debt benchmark the AER determined in the 2009 WACC parameters review. We note that the Chapter 6 WACC framework allows the AER to adopt a different DRP benchmark (in terms of the credit rating or term to maturity of the risk free rate) in the event that the 2009 Statement of Regulatory Intent (SORI) values are no longer applicable. To date, the AER has not sought to depart from its 2009 SORI decision on the basis that the benchmark is no longer appropriate.

3. Measurement of the DRP

This section analyses the problems identified by the AER in relation to applying the debt risk premium (DRP) benchmark, and provides an assessment of the DRP methodology used by the Economic Regulation Authority (ERA) and the Independent Pricing and Regulatory Tribunal (IPART).

In particular, the AEMC observes that the AER has "encountered problems in applying the specified DRP benchmark due to a lack of sufficient market data, hindered by the impact of the GFC on bond markets. The AER states that finding information on bonds that match or even approximate the 10 year term and BBB+ credit rating (as determined in the 2009 WACC review) is extremely difficult under current market circumstances".[13] Further, the AER contends that "the last time an Australian dollar denominated ten year corporate bond with a BBB+ credit rating was issued in the Australian bond market was June 2006."[14]

This section of our report examines these propositions in light of the history of Australian Competition Tribunal (Tribunal) decisions reviewing the AER's DRP methodology, as well as more recent AER decisions. We also examine the approaches undertaken by two other regulators that have been cited by the AEMC as being of interest, thereby addressing a particular question put in the Directions Paper, ie:[15]

> *What are the pros and cons of the recent approaches taken by IPART and the ERA in estimating the DRP?*

The remainder of this section is structured as follows:

- section 3.1 describes the past methods used by AER to estimate the DRP, highlighting that the AER is not restricted in the data it can assess to estimate the benchmark DRP; and
- section 3.2 provides an overview and then a high level analysis of the DRP methodology used by both IPART and the ERA.

3.1. Measurement of the DRP by the AER

The measurement of the DRP has in recent years been the subject of contention (including litigation) between the AER and NSPs. In part this reflects the intrinsic uncertainty associated with estimating the yield on BBB+ rated Australian corporate debt with a term to maturity of 10 years following the GFC.

We note in section 2 that one effect of the GFC was to change investors' appetite for longer term debt, itself reflecting the drop in supply of investor funds for all forms of risky assets. The consequence of the reduced demand for long term debt was both a more limited number of new long term debt issues (including, for a period, the complete absence of such issues) and a reduction in the number of market transactions in existing long term debt. This meant

[13] AEMC Directions Paper, page 98.

[14] AER, *Economic Regulation of Transmission and Distribution Network Service Providers, AER's Proposed Changes to the National Electricity Rules*, Rule Change Proposal, September 2011, page 78.

[15] AEMC Directions Paper, page 120.

that, for a period of time, there were limited, directly observable data on the debt benchmark, ie, BBB+ rated Australian corporate debt with a term to maturity of 10 years.

In our opinion, these market-based challenges for the measuring the DRP were exacerbated by a series of decisions by the AER to limit the amount of information to which it was willing to have regard when estimating the debt benchmark. For example, the AER's position in ActewAGL gas networks 2010 decision was to:[16]

- define a population of bonds that excluded all bonds:
  - that were not rated BBB+ by Standard and Poor's;
  - that did not have yields quoted by Bloomberg, CBASpectrum and UBS;
  - that were not fixed rate bonds;
  - not issued in Australia;
  - issued in Australia by non-domestic corporate entities;
- remove any bonds for which the yields were not representative of their credit rating; and
- analyse whether the Bloomberg or CBASpectrum fair value curves were a better fit for the remaining sample of bonds.

The AER explicitly rejected a CEG report that advocated the use of floating rate bonds (which included analysis demonstrating the equivalence of debt risk premia on fixed rate and floating rate bonds) and using bonds with a BBB and A- credit rating to assist to infer the debt risk premium for a bond with a BBB+ credit rating.[17]

The Tribunal stated that:[18]

> *… ActewAGL says that the bonds selected by the AER do not provide a basis for comparison with the fair value curves because the number of bonds is too small and their maturities are too short to be sufficiently representative of the yield on 10-year bonds.*
>
> *The Tribunal accepts this submission.*

Following the recent decisions by the Tribunal it is now accepted that when estimating the benchmark DRP a wider set of bonds should be considered, including bonds with a BBB and A- credit rating, floating bonds and bonds that are quoted by at least one reputable data source. In our opinion, these developments underline that the current NER already provide the AER with sufficient flexibility to estimate the debt benchmark, including during periods when the available data on bonds that precisely reflect the benchmark is poor.

This broader interpretation of the benchmark estimation process is apparent in the AER's recent draft decisions in relation to Powerlink and Aurora, which confirm that when

[16] AER, *Access arrangement proposal – ACT, Queanbeyan and Palerang gas distribution network 1 July 2010 to 30 June 2015: Final decision – Public*, March 2010, page 42.

[17] AER, *Access arrangement proposal – ACT, Queanbeyan and Palerang gas distribution network 1 July 2010 to 30 June 2015: Final decision – Public*, March 2010, pages 46-47.

[18] Application by ActewAGL Distribution [2010] ACompT 4 (17 September 2010), paragraphs 38 and 39.

estimating the DRP benchmark the AER can, and has had, regard to a wide body of “like” bonds that may differ from the benchmark in terms of:

- term to maturity;
- credit rating. ie, the AER has considered BBB, BBB+ and A- debt; and
- floating versus fixed rates.
- whether or not the bonds contain embedded options, provided that suitable adjustments can be made.

3.2. The ERA and IPART approaches to estimating the DRP

This section describes the method used by the ERA and the IPART to estimate the DRP.

3.2.1. ERA approach

The ERA’s most recent regulatory determination is its draft decision in relation to Western Power.[19] In this decision, the ERA reached the view that a debt benchmark for Western Power should have the following characteristics:

- a credit rating of A-; and
- a term to maturity of 5 years.

The benchmark credit rating was based on the median credit rating of Australian energy companies specified in the AER’s WACC Review in 2009, together with Synergy (the A+ rated electricity retailer in Western Australia).[20] The term to maturity of both the DRP and the risk free rate were set to match the length of the regulatory period (of 5 years).[21]

In order to measure the DRP, the ERA used the ‘bond-yield approach’ that it had previously applied in its final decisions on Western Australia Gas Networks Access Arrangement and the Dampier to Bunbury Natural Gas Pipeline.[22,23] The bond-yield approach has the following features:

1. A benchmark sample of Australian corporate bonds is developed. The ERA notes that each bond in this sample should *ideally* satisfy three criteria, namely:[24]

19 See, Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012.

20 Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, page 174.

21 Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, page 158-160.

22 See, Economic Regulation Authority, *Final Decision on WA Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011.

23 See, Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 31 October 2011.

24 Economic Regulation Authority, *Final Decision on WA Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011, page 78.

- have the same credit rating as the regulated business – for Western Power, this translates into all bonds in the sample having a credit rating of A-;
- be in the same industry, ie, the regulated utility sector – however, given the small number of energy sector bonds traded in the financial market, the ERA relaxed this restraint and included all bonds issued in Australia by Australian entities and denominated in Australian dollars; and
- a term to maturity of at least two years.

- This bond sample includes fixed bonds, floating bonds, and bullet and callable/putable[25] redemptions. In the Western Power draft decision, this resulted in a sample of 27 bonds as at 29 February 2012.[26]

2. The ERA then considered different scenarios in order to estimate the DRP – in the Western Power draft decision, the ERA had regard to the following two scenarios:[27]
   - the full sample of 27 bonds (scenario 1); and
   - a subset of the 27 bonds, where this subset consists of all the bonds with at least 5 years to maturity (scenario 2) – resulting in a sample size of 9 bonds.
3. For each bond in the full sample, the ERA estimated a corresponding risk free rate, where this risk free rate depends on the bond's term to maturity. The risk free rate for each bond was calculated by adjusting the ERA's estimate of the 5-year nominal risk free rate to reflect the term to maturity of the bond.[28] In other words, for all bonds in the sample that do not have five years to maturity, the risk free rate is adjusted to match the bond's own term to maturity.
4. The DRP for each bond in the full sample was then calculated as the difference between the observed yield[29] and the adjusted risk free rate (from step 3).
5. For each scenario considered in step 2, the ERA calculated four different measures of the average DRP:[30]
   - a simple arithmetic average;

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25 The ERA states that a "callable (putable) bond includes a provision in a bond contract that gives the issuer (the bondholder) the right to redeem the bonds under specified terms prior to the normal maturity date. This is in contrast to a standard bond that is not able to be redeemed prior to maturity. A callable (putable) bond therefore has a higher (lower) yield relative to a standard bond, since there is a possibility that the bond will be redeemed by the issuer (bondholder) if market interest rates fall (rise)."
Economic Regulation Authority, *Final Decision on WA Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011, page 79.

26 Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, page 181.

27 Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, page 181.

28 Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, page 182.

29 Calculated as the average of the fair yields in the average period – a 20 day trading period up to 29 February 2012 was used in the Western Power draft decision.
Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, page 183.

30 Economic Regulation Authority, *Final Decision on WA Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011, page 79.

  - a term-to-maturity weighted average – bonds with higher terms to maturity are weighted more than bonds with lower terms to maturity;
  - an amount-issued weighted average – bonds with a higher total issued value are weighted more than bonds with a lower total issued value; and
  - a median.

However, to set the DRP for Western Power, the ERA used a simple average of the two term-to-maturity weighted average scenarios.[31]

As a matter of principle, the AER would not be prevented from adopting elements of the ERA approach since:

- the NER provide for the AER to review and alter its debt benchmark (ie, term of the risk free rate or credit rating), either through an updated Statement On the Cost of Capital (SOCC) or, under Chapter 6 of the NER, at the time of a determination if there is persuasive evidence for change; or
- the AER could in any case adopt the ERA's sampling/yield aggregation approach to estimating a benchmark DRP (whether or not it had altered the benchmark).

Notwithstanding, in our opinion the ERA's approach involves a number of material errors, including that:

- the adoption of a 5 year term to maturity does not reflect the long term financing practice of regulated businesses, which demonstrably do finance debt at issuance with terms to maturity on average greater than 10 years (as the AER itself concluded in its 2009 SORI);
- the inclusion of Synergies (a government owned energy retailer, with a credit rating of A+) is an inappropriate comparator for a standalone NSP;
- there are significant methodological problems with the approach adopted by the ERA to the estimation of its benchmark, ie:
  - the sample involves bonds with terms to maturity that range from 2.09 years to 10.31 years and have a weighted average life of 6.9 years, rather than the benchmark of 5 years;
  - there is little theoretical basis for the effective weights that the ERA places on individual bonds, which place greatest weight on with the longest life rather than those that are closest to the benchmark.
- implicit in the ERA methodology is a linear relationship between term to maturity and yields, when this is not supported by the data, which show a non-linear relationship between term and yields; and
- the ERA rejection of the Bloomberg fair value curve (FVC) ignores a respected market estimate of the benchmark and is inconsistent with recent Tribunal decisions.

31 Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, paragraph 775.

3.2.2. The IPART approach

IPART's most recent DRP determination was made in the context of its final decision in relation to the Sydney Desalination Plant (SDP).[32] IPART established a debt benchmark with the following characteristics: [33]

- a credit rating of BBB/BBB+; and
- a term to maturity of five years.

IPART's methodology for estimating the DRP by reference to that benchmark was: [34]

1. based on a sample of yields that included the Bloomberg BBB 5-year fair value curve, as well as Australian and US bonds that met the following conditions:
   - issued by an Australian firm;
   - with a remaining term to maturity of at least two years – IPART did not impose an upper limit on the term to maturity, and stated that "the criteria of selecting bonds with at least 2 years remaining to maturity balances the need to include only relevant observations with the requirement of having a sufficient number of observations";[35]
   - a BBB to BBB+ rating by Standard &Poor's;
   - fixed, unwrapped and without embedded options;
   - unaffected by factors such as M&A activity; and
   - a price published by Bloomberg.

   IPART stated that the small number of bonds issued in Australia by Australian firms that met the above conditions led to it expanding the sample to include bonds issued in the US by Australian firms.[36] IPART considered that including these US bonds increased the sample size and also improved the quality of observations.[37]
2. IPART calculated the average DRP for each financial product in the sample (ie, for each bond and the Bloomberg BBB 5-year fair value curve) over a 20-day sampling period;[38]
3. The median of the above DRP estimates was determined – IPART considered a number of approaches to establishing a point estimate of the DRP – including the establishment of a range – and determined that the median was the most appropriate.[39] IPART's preference or a median was based on the principle that this placed no weight on outliers and so

[32] See, IPART, *Review of Water Prices for Sydney Desalination Plant Pty Limited, Water – Final Report*, December 2011.

[33] IPART, *Developing the Approach to Estimating the Debt Margin, Other Industries – Final Decision*, April 2011, page 3; and IPART, *Review of Water Prices for Sydney Desalination Plant Pty Limited, Water – Final Report*, December 2011, page 86.

[34] IPART, *Developing the Approach to Estimating the Debt Margin, Other Industries – Final Decision*, April 2011, pages 2-3.

[35] *Ibid*, page 34.

[36] *Ibid*, page 31.

[37] *Op. Cit.*

[38] *Ibid*, page 87.

[39] *Ibid*, page 34.

provided a measure of central tendency for a small sample.[40] However, IPART note that "the use of the median may not be consistent with our approach to setting other WACC parameters."[41]

4. IPART then added a debt raising allowance of 20 basis points to the median estimated in step 3. An allowance of 20 basis points was based on the assumption that the current cost of raising corporate debt was 12.5 basis points, [42] ie, 12.5 basis points amortised over 5 years in present value terms is approximately 20 basis points in present value terms.[43] IPART noted that the cost of raising corporate debt may have changed and that it will continue to research the appropriate debt raising costs.[44]

This method resulted in a DRP of 3.5 per cent for SDP.[45]

Again note that, as a matter of principle, both the NER and the NGR would allow the AER to adopted IPART's approach, although for electricity transmission determinations the AER would need to wait until the publication of the next SORI to change the debt benchmark.

Notwithstanding, in our opinion IPART's approach contains a number of errors, including:

- the adoption of a 5 year term to maturity does not reflect the long term financing practices of regulated businesses, which demonstrably do finance debt at issuance with terms to maturity on average greater than 10 years (as the AER itself concluded in its 2009 SORI);
- IPART provides little or no analysis on the construction of its sample of like bonds, stating only that:[46]

  > *the criteria of selecting bonds with at least 2 years remaining to maturity balances the need to include only relevant observations with the requirement of having a sufficient number of observations*

- IPART provides no analysis as to why the median bond yield (ie, average of Leaseplan Australia and Sydney Airport F bond issues) best represents the likely benchmark yield for a bond with a credit rating of BBB/BBB+ and a term to maturity of 5 years.

The AEMC has identified that one of five criteria for a good WACC framework is that it creates accountability for both the regulator and the NSP/gas pipeline. In our opinion IPART's approach to estimating the DRP benchmark does not satisfy this criterion because it does not articulate the reasons for critical elements of its decision, particularly where it has exercised discretion on matters that have a significant effect on the outcome.

40 *Op. Cit.*

41 *Ibid*, page 35.

42 *Ibid*, page 27.

43 *Op. Cit.*

44 *Op. Cit.*

45 *Ibid*, page 87.

46 *Ibid*, page 34.

3.3. Conclusion

The ERA and IPART have both adopted debt benchmarks that differ from that determined by the AER, in that:

- the term to maturity is 5 years, rather than the 10 years adopted by the AER; and
- the credit rating is A- (ERA) or BBB/BBB+ (IPART), rather than the BBB+ credit rating assumed by the AER.

However, as a matter of principle, both the NER and the NGR would permit the AER to adopt either of the debt benchmarks determined by the ERA or IPART, if the evidence led to the conclusion that those benchmarks better reflected the financing decisions and constraints of benchmark, efficient stand alone gas pipelines and/or electricity network businesses.[47] Notwithstanding, in our opinion the debt benchmarks applied by the ERA and IPART are not consistent with the financing decisions and constraints of regulated energy.

In terms of the methods used to estimate the cost of debt that is consistent with the chosen benchmarks, both the ERA and IPART estimate the benchmark DRP by reference to a sample of comparable bonds. In that respect, their approaches are similar to that recently adopted by the AER in its draft decisions for Powerlink and Aurora, although the merits of this approach remain to be tested under the merits review provisions.

[47] The NGR does not restrict the AER from immediately adopting these benchmarks. However, for electricity transmission determinations the AER would need to wait until the publication of the next SORI to change the debt benchmark

4. Market Analyst Reports

The AEMC's Directions Paper refers to a number of reports from equity market analysts on publicly listed energy utilities and concludes that a number of these reports indicate that the valuations placed on the businesses by the analysts assume "an ability for the NSPs to raise debt at a rate lower than the cost of debt allowed by the regulator". Further, the AEMC states that a number of the reports indicate that a "major reason why they value the NSPs at above their RAB is due to their ability to out-perform their cost of debt allowance." [48]

This section of our report addresses the particular question posed by the AEMC, ie:[49]

> *What weight should be placed on the views of market analysts on the ability of stock market listed NSPs to out-perform their cost of debt allowances?*

We discuss the concept of the ability of NSPs to outperform (or appear to outperform) the debt benchmark in section 2. In this section, we examines the AEMC's conclusion that a major reason that the value of NSPs is above their RAB is their ability of outperform their cost of debt allowance.

By contrast to the conclusion drawn by the AEMC, our review of the identified analyst reports indicates that:

- none directly identify the ability to outperform the debt benchmark as the primary reason for the NSP trading at a multiple of its RAB; and
- the observation that regulated NSPs trade at a multiple of their RAB does not necessarily indicate that there is a problem with the cost of debt benchmark because:
  - there are a number of sound reasons for an NSP to trade at a multiple of its RAB;
  - Australian regulated NSPs traded at multiples of their RAB (and at higher multiples than at present) even when the cost of debt allowance was not considered to be 'too high'; and
  - Internationally, NSPs generally also trade at a multiple of their RAB, and in many cases at multiples significantly higher than those of Australian NSPs.

4.1. Review of the identified analyst reports

None of the market analyst reports identified by the AEMC provides a detailed assessment of either:[50]

- the appropriateness of the current debt benchmark applied by the AER; or

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48 AEMC Directions Paper, p.108.

49 AEMC Directions Paper, p.120.

50 We note that none of the analyst reports detail the analysis that they have undertaken. Therefore, we cannot confirm whether the DRP calculation is correct or not. For example, it is not clear that when analysts quote actual DRP whether they are referring to the debt risk premium relative to the 10 year government bond rate; or to the credit margin over the floating Bank Bill Swap Reference Rate (BBSW). The credit margin over the floating BBSW is generally about 50 basis points lower than the DRP relative to the 10 year government bond rate.

- the methodological issues or their application in the estimation of the DRP benchmark by either the AER of the Tribunal.

Only one analyst report (Credit Suisse) discusses the current rule change process in relation to the DRP in any detail, but this report does not analyse the relative merits of the current debt benchmark or its measurement. Rather, it notes that:[51]

> *[O]verall, we take a conservative stance […] to assume that the regulator wins this battle with the utilities (and is able to find a methodology that offers way of estimating the debt risk premium) […] We also take the view that given this is a regulatory risk factor; we would rather leave a positive outcome as upside in our valuations*

In other words, the stated purpose of the analyst report was to provide its clients with a 'worst case' scenario of rule change being successful. The objective was not to comment on the appropriateness or relevance of the benchmark.

A number of other analyst reports indicate that regulated NSPs have traded at multiples of their RAB including:

- since 2007, the regulated utilities sector has traded on an average RAB multiple of 1.25x;[52]
- DUET and SP AusNet are currently trading on at RAB multiples of 1.15x and 1.17x respectively;[53]
- APA currently has an implied 1.2x RAB multiple and that this is in line with the 1.15-1.25x RAB multiples that listed regulated utilities are trading at present; [54] and
- JP Morgan has applied a RAB multiple of 1.1x to the NSW distribution assets, with this being slightly below the multiple that they derive in the valuation of DUET Group, Spark Infrastructure and SP AusNet's electricity distribution businesses further it has applied a slightly higher multiple to the transmission business. [55]

Our review of each of the analyst reports identified by the AEMC in its Directions Paper shows that none indicate that the DRP benchmark is the primary cause of listed NSPs trading at a multiple of their RAB.[56]

4.2. Value of company larger than RAB

The regulatory framework is designed to reward NSPs that are able to outperform pre-specified benchmarks, such as, service performance standards, operating and capital expenditure allowances and their cost of capital benchmarks. Firms that are consistently able to outperform would be expected to trade at multiples of their RAB. Importantly, the multiple

[51] Credit Suisse, Regulated Utilities Sector Review, Debt Risk Premium at risk in future WACCs, 4 November 2011.

[52] Merrill Lynch, Sustainable yield plus growth, 5 October 2011.

[53] Merrill Lynch, Soft volumes offset by tariff increase, 9 November 2011.

[54] Merrill Lynch, APA – Not a done deal, 14 December 2011.

[55] J.P. Morgan, The Wire, 3 November 2011.

[56] A summary of each of the analyst reports is set out in Appendix A to this report.

would reflect the combined effect of current and expected outperformance across the totality of the aspects of business performance.

We note that the phenomenon of NSPs trading at multiples of their RAB is not new, and extends over a much longer period of time than the period in which the DRP benchmark and its estimation has come to received significant attention. NSPs have historically traded at a multiple of their RAB. Indeed, previously the Australian Competition and Consumer Commission (ACCC) recognised that the ratio of enterprise value (EV) to regulated asset base (RAB) ranges from 1.4 to 1.6.[57] This observation was based on a report prepared by ACG for the ACCC.[58] Prior to the GFC several transactions of Australian regulated businesses took place at RAB multiples larger than 1.5.[59]

It is common for NSPs in other jurisdictions also to trade at multiples of their RAB. Table 4.1 sets out examples of recent estimates of RAB multiples for international companies. This demonstrates that regulated firms typically trade above their RAB value. By way of example, the average EV/RAB multiple for transactions in the New Zealand electricity distribution sector over the past decade has been 1.9. [60]

In our opinion, the fact that NSPs are observed to be trading at multiples of the RAB at present provides no foundation for an inference that the DRP element of AER determinations is inappropriately high. On the contrary, NSP valuations as a multiple of RAB values have tended to contract in recent years, right during the period when the suggestions that the DRP is overstated have come to the fore. Rather, insight into the nature and extent of any problems that may exist in relation to the DRP benchmark and its estimation is likely to be gained by examining the detailed basis for the particular DRP decisions and attempting to draw common themes from them – a perspective that extends well beyond the scope of most equity analyst commentary.

Table 4.1
Enterprise Value to RAB multiple

Company	Country	EV/RAB multiple	Sector	Date
Vector	New Zealand	1.23x-1.35x	Electricity	2010
Horizon Energy	New Zealand	1.5x	Electricity	2010
National Grid	United States	1.3x	Electricity	2011
Southern Water	United Kingdom	1.44x	Water	2007
Auckland International Airport	New Zealand	1.2x	Aviation	2010

Source: Cameron Partners, Report to Transpower New Zealand Limited: Relating to a market based rate of return assessment, 16 August 2010; Morgan Stanley, National Grid plc, 2 February 2011; CIMB Research Report, YTL Power International, 19 October 2007;JBWere, Auckland International Airport Limited, 29 January 2010.

57 ACCC, Submission to the Productivity Commission Draft Report: Review of the Gas Access Regime, 17 March 2004.

58 Allen Consulting Group, *Review of studies comparing international regulatory determinations*, 2004.

59 Deloitte Corporate Finance, Regulated assets: Trends and investment opportunities, July 2011.

60 Cameron Partners, Report to Transpower New Zealand Limited: Relating to a market based rate of return assessment, 16 August 2010, p.25.

Appendix A. Review of Market Analyst Reports

In this appendix we undertake a review of the market analyst reports that have been referenced in the AEMC Directions Paper. We note that these have been provided to us by the AEMC.[61]

A.1. Credit Suisse

The analyst report that covers the DRP issues in most detail is that of Credit Suisse.[62] The focus of the Credit Suisse report is to provide information to the market on how, under a 'conservative stance', the proposed rule change may impact the performance of the publicly listed NSPs.

The report notes that "many utility companies continue to hold debt within their portfolios at a lower cost than spreads available in today's markets."[63] We do not dispute this. However, this does not recognise that regulated businesses face refinancing risks. This was discussed in section 2.1.

The report notes that the AER may either seek to change the model (benchmark) company, or the methodology it uses to estimate the DRP (ie, the issues that we set about above in section2). However, it considers it is more likely for the AER to propose to change the methodology used.

Credit Suisse's conclusions regarding the appropriate level of the DRP are drawn from Figure 12 in the report (reproduced below as Figure 3.1). We note that Credit Suisse states that the consideration of an appropriate DRP is not an easy question to evaluate since credit ratings, debt tenures and sizes of businesses vary.

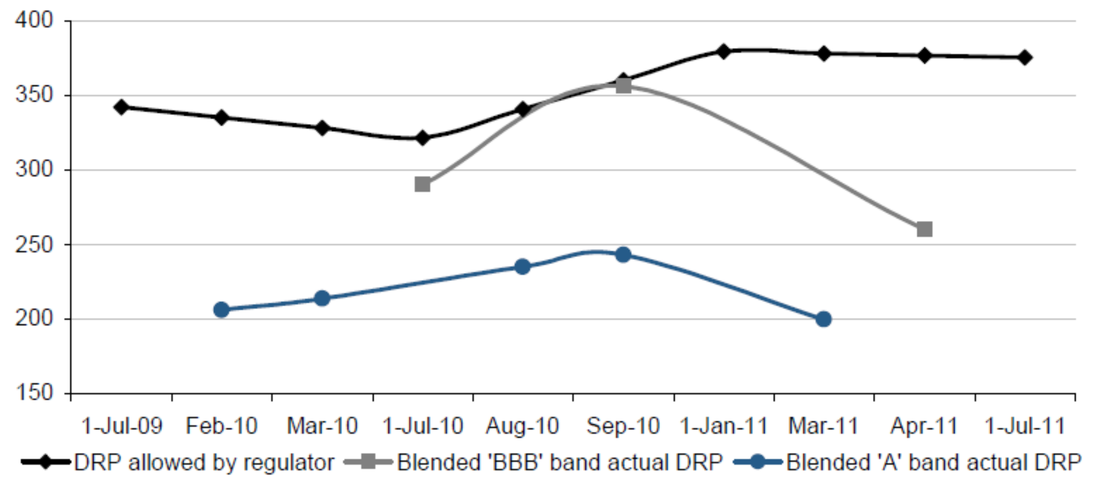
61 We note that the reports quoted are only a selection of reports that the AEMC has obtained some of the agencies and so is not comprehensive.

62 Credit Suisse, Regulated Utilities – debt risk premium at risk in future WACCs, 4 November 2011. (Hereafter: 'Credit Suisse' report).

63 Credit Suisse, RUM – DRP at risk – 4 November 2011, p.9.

Figure A.1 Credit Suisse – Trends in regulated DRP and actual DRP (basis points)

Figure 12: Trends in regulated debt risk premium and actual DRP (basis points)



Source: Australian Energy Regulator, Credit Suisse estimates

The first observation that Credit Suisse make is that the 'free kick' provided by the DRP is "probably not as wide as feared by some market participants".

Using this information contained in Figure A.1 as a basis, it concludes that an appropriate DRP for the AER to set would be in the range of 330-350 basis points. This has been determined as the average 'BBB" band DRP of approximately 300 basis points, plus a small 'insurance policy' for the AER. This extra amount is to mitigate any retardation in regulated investments, in case the AER estimates the DRP incorrectly. Credit Suisse then incorporates this updated DRP estimate (ie, of 330 basis points) into the valuations of the publicly listed companies – APA, DUET Group, Envestra, Spark Infrastructure Group and SP AusNet.

We note there are a number of limitations with this conclusion reached by Credit Suisse. First, this average DRP of 300 basis points for BBB rated utilities has been based on *three* data points. That is, the three blended 'BBB' band actual DRP points that are shown in 'grey' above. Three observations are insufficient to reach a sufficiently robust conclusion as to the 'average' BBB DRP to inform a regulatory proceeding. In addition, the Credit Suisse analysis has not taken into account the term to maturity of the BBB benchmark.

Similarly, we note that there are only *five* data points for A band DRP points – the 'blue' dots above. This is also an insufficient number to provide any conclusions. Again Credit Suisse analysis of A- rated bond yields ignores the effect that the term to maturity has on the observed yields.

We note that Credit Suisse state that the only way for utilities to receive 'A-' ratings is through their interaction with some of their investors. For example, SP AusNet higher rating is due to an implicit parental guarantee from Singapore Power, that has a higher credit rating ('AA-' rated).

Therefore, Credit Suisse has only considered either *three* or *five* data points to draw conclusions. This is a small sample size, and so is not sufficient to draw sufficiently robust conclusions to inform a regulatory proceeding.

Second, we note that the DRP reported in Figure 12 are all of indeterminate term. Therefore, any conclusions that can be drawn are unclear. Bonds of different terms have different debt risk premiums.

A.2. Merrill Lynch

There are three Merrill Lynch market analyst reports that have been provided to us. We discuss each of these in turn below.

A.2.1. October 2011

The October 2011 analyst report considers both DUET Group and Spark Infrastructure Group.[64] This report notes that the AER has proposed rule changes, but it does not specifically consider the proposed change to the DRP. It concludes that the rule changes may propose more uncertainties for the publicly owned NSPs.

It also notes that "since 2007, the regulated utilities sector has traded on an average RAB multiple of 1.25x". No commentary is provided surrounding this statement.

Lastly, it notes that in September, SP AusNet executed $500m of new bank debt facilities. While the margin was not disclosed by the company, Merrill Lynch understands that it may have been below 150 basis points. It considers that this is reflective of its A- rating, as well as banks' willingness to lend to regulated utilities.

A.2.2. November 2011

The November 2011 analyst report considers SP AusNet.[65] The report notes that the AER has proposed a number of rule changes, and that DUET and SP AusNet are currently trading on RAB multiples of 1.15x and 1.17x respectively. It does not provide commentary on either of these issues.

We note that it does set out that SP AusNet is currently appealing its debt margin to the Australian Competition Tribunal (the Tribunal). SP AusNet is requesting a debt margin of 4.22% versus the 4.05% it was given by the AER. Merrill Lynch consider that this is a "little optimistic" given improving debt market conditions, and the fact that recent debt for A-rated regulated utilities have been priced at around 150-200 basis points. We note that the Tribunal decided in favour of SP AusNet and so concluded that a debt margin of 4.225 per cent should be applied.

Merrill Lynch notes that in June the AER set a DRP of 381 basis points for Envestra. However, recent debt raisings and refinancing by regulated utilities have all been struck at below 250 basis points. We consider that this is consistent with the idea that yields change over time, and discussed this in further detail in section 2.2.

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64 Merrill Lynch, Sustainable yield plus growth, 5 October 2011.

65 Merrill Lynch, Soft volumes offset by tariff increase, 9 November 2011.

A.2.3. December 2011

The December 2011 analyst report considers APA.[66] This report does not consider the AER rule changes. However, it does note that APA currently has an implied 1.2x RAB multiple. Further, that this is in line with the 1.15-1.25x RAB multiples that listed regulated utilities are trading on at present.

We consider the reasons why companies may be valued higher than their regulated values in section 2.3.

A.3. Macquarie Equities Research

Two Macquarie Equities Research reports have been provided to us. We consider each of these in turn below.

A.3.1. October 2011

The October 2011 report considers Spark Infrastructure Group.[67] It specifically considers the AER proposed rule changes. It notes that it considers that "resetting the debt risk premium approach to be decided in a WACC review […] makes sense." although fails to provide its reasons for this conclusion. However, the proposed rule change did not result in it lowering its expectations of future DRP decisions

A.3.2. November 2011

The November 2011 report considers DUET Group.[68] The report notes that the DRP set by the regulator is likely to be higher than actual rates.

For example, the DBP[69] received a ~320 basis points DRP from the Economic Regulatory Authority (ERA) of Western Australia. However, this is compared with raising money at ~175 basis points. The analyst notes that while such a gap may seem 'high' it reflects the company's willingness to arbitrage the bond curve. Implicitly the regulated assets are being rewarded for taking the duration mismatch risk ie, 'refinancing risk'.

We considered this in section2.2.

A.4. JP Morgan

We have been provided with two JP Morgan reports. We consider each of these below.

66 Merrill Lynch, APA – Not a done deal, 14 December 2011.

67 Macquarie Equities Research, Spark Infrastructure Group – AER rule change – a fight brewing, 4 October 2011.

68 Macquarie Equities Research, DUET Group – Limited RAB growth – at fair value, 7 November 2011.

69 DBP is the trading name of the privately-owned group of entities which own and operate the Dampier to Bunbury Natural Gas Pipeline (DBNGP) – the key gas transmission pipeline in Western Australia. DBP's shareholders are DUET Group (80%) and Alcoa (20%).

A.4.1. August 2011

The August 2011 report considers a number of regulated businesses.[70] This report does not comment on the AER rule changes.

It does set out that there has been increasing credit risk over the month of August – this is noted using the Markit iTraxx Australia Index, a gauge of the measurement of the credit risk facing local borrowers. It notes that if this represents "a developing and persistent upward trend, [then] the ensuring funding blowout may have disastrous consequences for BBB rated utilities seeking to tap the market for debt financing".[71]

A.4.2. November 2011

The November 2011 report considers a number of regulated businesses.[72]

It notes that "while margins remain higher than pre-GFC levels, funding costs have diminished materially since 2008-09".[73] It then provides examples of this. We do not disagree with these. It states that recent refinancing by companies shows a preference for shorter dated funding and concludes that this can be explained by the yield curve – there are relatively attractive margins at 3 year corporate BBB bonds. We note that this is not inconsistent with our analysis in section 2.2, but note that the shorter term debt brings with it higher refinancing risk.

It also considers the outcomes of the Tamberlin Report in the NSW asset sell off. It notes that it has applied a RAB multiple of 1.1x to the NSW distribution assets, with this being slightly below the multiple that they derive in the valuation of DUET Group, Spark Infrastructure and SP AusNet's electricity distribution businesses. It has applied a slightly higher multiple to the transmission business.

70 J.P. Morgan, The Wire, 12 August 2011.

71 J.P. Morgan – The Wire – DUE regulatory approval, 12 August 2011

72 J.P. Morgan, The Wire, 3 November 2011.

73 J.P. Morgan, The Wire – NSW Power sell-off, 3 November 2011.

Appendix B. Authors

Jeff Balchin is a Principal in the PwC Economics and Policy team, previously being a director of the Allen Consulting Group and prior to that in various positions in the Commonwealth Government. Jeff has over 17 years of experience in relation to economic regulation issues across the electricity, gas, airports, ports and water industries in Australia and New Zealand. He has been an adviser to governments, regulators, customers and infrastructure providers on the design, economic interpretation and application of economic regulation, which has included key roles in many of the landmark matters.

Greg Houston is a Director of NERA Economic Consulting, based in Sydney. Greg has twenty five years' experience in the economic analysis of markets and the provision of expert advice in litigation, business strategy, and policy contexts. Greg's work in the Asia Pacific region principally revolves around the activities of the enforcement and regulatory agencies responsible for competition, economic regulation and securities market matters, many of whom also number amongst his clients. In December 2005 Greg was appointed by the Hon Ian Macfarlane, then Minister for Industry, Tourism and Resources, to an Expert Panel to advise the Ministerial Council on Energy on achieving harmonisation of the approach to regulation of electricity and gas transmission and distribution infrastructure in Australia. During the 2005-06 period Greg also advised both the AEMC and the Ministerial Council on Energy on the development of the rules now applying to both the transmission and distribution network service providers.

Brendan Quach is a Senior Consultant of NERA Economic Consulting and has eleven years experience as an economist, specialising in network economics, and competition policy in Australia, New Zealand and Asia Pacific. Brendan specialises in regulatory and financial modelling and the cost of capital for network businesses. Brendan was involved with the initial development of the chapter 6A provisions of the national electricity rules.

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ENA submission – 16 April 2012

Attachments C, E and F

Attachment C – Joint Report – Capital and Operating Expenditure – Response to the AEMC Directions Paper (60 pages)

Attachment E – Joint Report – Trailing Average Approaches to the Cost of Debt Allowance (19 pages)

Attachment F - Farrier Swier Consulting Report – Assessment of Proposed Changes to Regulatory Process and Practice Rules (70 pages)

Attachment C

Joint Report

NERA Economic Consulting and
PwC

Attachment C – Joint Report – Capital and Operating Expenditure – Response to the AEMC Directions Paper

Capital and Operating Expenditure – Response to the AEMC Directions Paper

A joint report for the
Energy Networks Association

16 April 2012

Project Team

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Executive Summary

The purpose of this report is to address a number of matters arising in relation to the regulatory framework for capital and operating expenditure, and in particular:

- to review the policy intent of the current Chapter 6A Rules and (a) to identify the extent to which the AER has applied the Rules in line with the policy intent, and (b) to consider whether the policy intent remains appropriate given developments in economic regulation internationally;
- to consider the incentives for efficient capital and operating expenditure, including identifying the appropriateness of a symmetric incentive scheme, and outlining the criteria that might apply to an efficiency benefits sharing scheme for capital expenditure; and
- to identify principles that should be taken into account so that risks and the scope for economic harm is minimised should the AEMC find that there is merit in introducing an ex-post prudence test of expenditure.

Operation of Chapter 6A in the context of the policy intent

In its rule change proposal, the AER contends that the requirement upon it to start from the NSP's regulatory proposal and then accept the expenditure forecast component if it is satisfied that this forecast 'reasonably reflects' the operating expenditure criteria allows network businesses to propose 'the highest possible forecast'.[1] Further, the AER contends that this leaves the evidentiary burden on it to prove that the proposed forecast is neither efficient nor prudent.

In its recent Directions Paper the AEMC stated that the analysis of the data and submissions do not support the AER's claim that it has been limited in its assessment of capital and operating expenditure proposals under the Rules.[2] In analysing this issue the AEMC refers to the 'policy intent' as being that set out in the Chapter 6A rule determination and described in section 3.2.2 in its Directions Paper.[3]

In assessing the outcomes that have occurred under the current framework, in our opinion the actions of the AER have been consistent with the AEMC's initial policy intent, ie:

- the AER has given considerable attention to NSPs' proposals, using them as a starting point and placing them at the centre of its analysis, as intended by the Commission in order to mitigate regulatory risk;

1 AER, *Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules*, September 2011, page 25.

2 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* Directions Paper, March 2012, page 29.

3 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* Directions Paper, March 2012, page 28.

- the requirement to accept forecasts that the AER is satisfied 'reasonably reflect' the criteria has not resulted in the AER either:
  - needing to establish a range of acceptable levels for operating and capital expenditure; or
  - being forced to accept forecasts that it considers inappropriately high, since in each case the AER has rejected the relevant TNSP's forecasts, replacing them with its own forecasts.

This experience is not consistent with any deficiency in the current Rules as they relate to the Commission's policy intent. Further, the evidence of regulatory practice internationally also indicates that the original policy intent of the AEMC remains appropriate. International regulatory practice continues to place an NSP's proposal at the centre of analysis. In addition, given the scope for merits or judicial appeals, regulators have recognised that evidence based decision making is necessary for a stable and predictable regulatory framework. On that basis, there is no evidence to support the suggestion that either the principle of guided discretion or its application by the AER causes the existing Rules not to comply with the policy intent, or that the original policy intent is no longer relevant.

Capital and operating expenditure arrangements

With regard to the expenditure incentive arrangements we have been asked to consider the following specific questions:

- what incentives exist in the current framework for efficient operating expenditure?
- is a symmetric capital expenditure incentive scheme appropriate?
- what are our views on the AER's arguments for an asymmetric scheme?
- what criteria are recommended to inform the implementation and design of an efficiency benefits sharing scheme (EBSS)? and
- is actual or forecast depreciation appropriate when updating the regulatory asset base at the commencement of a regulatory period?

Incentives for efficient operating expenditure

A continuous incentive in the form of an EBSS current applies to operating expenditure for distribution and transmission businesses. The fundamental objective of this scheme is to enhance an NSP's incentive to pursue efficiency gains, particularly given the periodic nature of price reviews and the associated discontinuities in incentives around those reviews. The design of the AER's EBSS for operating expenditure seeks to achieve efficiency gains in the following ways:

- it seeks to balance the interests of NSPs with that of users in an attempt to mimic competitive market outcomes. This is achieved by allowing NSPs to retain the net present value of a gain or loss for a period of five years;
- a continuous incentive is provided such that the incentive to pursue efficiency gains is equal in each year of a regulatory control period; and

- committing to carry-forward the entire amount of any efficiency gain (or loss) for the specified period rather than adjusting the amount on an ad hoc basis, thereby providing certainty and predictability for NSPs.

Benefits of a symmetrical capital expenditure incentive scheme

We consider that the application of a symmetric capital expenditure scheme has a number of advantages over the present capital expenditure incentives, as well as the scheme proposed by the AER. There are three benefits from a symmetric capital expenditure incentive:

- it allows for a constant incentive for efficiency to be provided. This is desirable as it provides an incentive to NSPs to be efficient irrespective of whether an NSP expects to underspend or overspend versus its approved forecast;
- it can facilitate a better balance of incentives between capital and operating expenditure. As there is already a symmetric EBSS incentive scheme which exists for operational expenditure, absent a corresponding symmetric incentive for capital expenditure it is not possible for the incentives between operating and capital expenditure to be balanced; and
- it can allow for a better alignment with service performance incentives. Applying an EBSS to capital expenditure, and choosing the power of the incentive, allows the regulator to better calibrate the balance of incentives so that biases are minimised or eliminated.

Response to AER arguments in support of an asymmetric scheme

The AER has put forward three reasons why it has not developed an EBSS for capital expenditure and why an asymmetric scheme is preferred:

- the deferral of projects between regulatory periods could skew the potential benefits of the scheme in favour of NSPs;
- the main incentive problem to be remedied is NSPs overspending and an asymmetric scheme, as proposed by the AER, is preferable to address this problem; and
- an asymmetric scheme may better balance capital expenditure incentives with service performance incentives.

We consider that the concerns raised by the AER are not well founded. Further to this, even if the concerns were well founded, the appropriate solution would not be the introduction of an asymmetric scheme. Our reasons are the following:

- it is acknowledged that where an EBSS is applied to capital expenditure that the scope for inefficient deferrals between regulatory periods needs to be resolved. We consider that there may be practical solutions available to fix this issue and these have been applied in jurisdictions such as the United Kingdom by Ofgem and in South Australia by ESCOSA. We note, however, that to date a fulsome investigation of the options to address the issue of inefficient deferrals under an EBSS for capital expenditure has not been undertaken by the AER;

- one of the key objectives from capital expenditure incentives should be to provide NSPs with an incentive to make efficient decisions and control costs to the extent possible. This objective should be sought irrespective of how that business has performed compared to the forecast for the regulatory period. The implication is that the chosen incentive mechanism should ensure, to the extent possible, that the payoffs under the mechanism are symmetric such that improvements are rewarded and poor performance is penalised; and
- If there are concerns that there are 'gaps' that may allow NSPs to provide a level of service lower than that desired by customers, the solution should not be to implement an asymmetric scheme. If any asymmetric scheme were implemented an NSP would still have a strong incentive to avoid expenditure for service delivery, particularly if it expected to overspend during the period. Therefore, any concern about potential 'gaps' in service incentive schemes should be remedied by either resolving those gaps or by reducing the power of a symmetric incentive scheme.

Criteria for the development of a capital expenditure EBSS

We have built upon the analysis of capital expenditure incentives in our previous report to take the discussion of criteria for a capital expenditure EBSS further. Specifically, we have developed a number of criteria, in drafting instructions form, which we consider to be appropriate for a capital expenditure EBSS. While not expressed in full here, in summary, the criteria address the following:

- the AER should have discretion to implement an EBSS for capital expenditure;
- the objective of the scheme should be the promotion of the National Electricity Objective (NEO);
- the scheme should measure efficiency gains by comparing actual expenditure against the ex ante forecasts, except where adjustments are made to reflect:
  - events that are not within the full control of NSPs; or
  - where necessary to ensure that the measure of change in efficiency that is reflected in the EBSS calculation as closely as practicable reflects the actual change in efficiency;
- the scheme should provide a continuous and symmetrical incentive;
- the AER should consider a number of factors when determining the appropriate power of the incentive, including:
  - the desirability of generating a net benefit to customers;
  - the desirability of the scheme, in combination with other incentive arrangements, providing NSPs with an incentive to act in a manner consistent with the NEO, including to provide an optimal level of service and to minimise

  - the cost of this, taking into account other incentives and regulatory obligations; and
  - the residual risk that is created by the scheme after taking into consideration these factors;
- implement the scheme so to reduce the impact on NSPs and customers of events that are not within the full control of NSPs, including through:
  - making adjustments for categories of expenditure to reflect, to the extent practicable, events that have occurred during a regulatory period (provided the method for doing so is defined in advance);
  - considering whether certain classes of projects should be excluded from the scheme; and
  - considering whether a quantitative limit should be set for the impact of differences between forecast and actual expenditure;
- the implementation costs of the scheme; and
- parameters or values under the scheme may vary between NSPs or classes of NSPs over time.

Actual versus forecast depreciation

A particular issue that was noted in the previous joint expert report on capital expenditure incentives was that the choice of actual depreciation rather than forecast depreciation when updating the regulatory asset base at the commencement of a regulatory period can influence the relative incentives for assets with different economic lives. On this basis we considered the application of actual depreciation to be a second best approach to providing strengthened incentives for capital expenditure efficiency. Moreover, given the perverse incentives that the use of actual depreciation may create, its use may not be appropriate even if an EBSS for capital expenditure is not introduced.

To the extent that there is seen to be a continued role for the application of actual depreciation, we consider that this should be optional and guided by criteria in the Rules which might require the AER to:

- not apply actual depreciation if there is an EBSS for capital expenditure;
- before applying actual depreciation have regard to, amongst other things, the impact of its use on matters such as:
  - the balance of incentives between operating and capital expenditure;
  - the balance of incentives with service performance schemes; and
  - the relative incentive for expenditure on assets with differing economic lives.

Criteria for an ex-post prudence test

The ENA has requested that we identify design principles that should be applied to an ex-post prudence test should the AEMC deem that there is merit in considering its application further. We note, however, that experience to date indicates that it has been difficult to design and implement an ex-post prudence regime that achieves the desired objectives of promoting efficiency without causing economic harm due to an inappropriate increase in risk.

The following principles seek to ensure that, to the extent possible, the introduction of the scheme does not lead to outcomes that do not promote the NEO:

1. The test should be designed so that the regulator only uses the information that a prudent NSP would have used in order to come to the decision of whether to invest or not in the absence of the ex post test. This serves to:
   A. limit the assessment to information that was available at the time of the decisions were made; and
   B. further limited the information to that which would have appeared relevant at the time.
2. The test should be one of prudency, not best practice. Tests of best practice are likely to materially reduce the incentives for the NSPs to undertake investments (even when they are efficient) as it creates significant uncertainty that an investment will pass the test.
3. The regulator should be required to assess NSP's decisions, rather than benchmarking cost outcomes. The cost of provision of services is dependent on the unique characteristics of the NSPs. The use of benchmarking to assess the efficient cost of outcomes would pose an unacceptable risk of error.
4. The onus of proof should be on the AER to prove that expenditure was inefficient, rather than on the NSPs to prove its efficiency. This will limit the risk that the regulator, in error, does not allow a prudent investment to be rolled into the RAB.
5. Limit the use of an ex post prudence test to large investments that are materially above forecast (or were not included in the forecast at all) through the use of a materiality threshold. This would serve to minimise the regulatory burden of the tests.
6. The test should be designed so that the regulator must specify guidelines in an upfront and transparent manner, setting out what is required for it to pass or fail the test.
7. The appeal mechanism should extend to the AER's decisions under an ex post prudence test.

1. Introduction

This report has been jointly prepared at the request of the Energy Networks Association (ENA), for submission to the Australian Energy Market Commission (AEMC). Its subject is the framework for expenditure forecasts and incentives for efficient operating and capital expenditure. The report is part of a response to a rule change proposal put forward in September 2011 by the Australian Energy Regulator (AER) for decision by the AEMC.

1.1. Authorship of the report

The authors of this report are: Jeff Balchin, Principal of PwC Australia, and Greg Houston, Director of NERA Economic Consulting. Greg and Jeff are both economists with substantial expertise in the economic regulation of network infrastructure services. This particular report has also been co-authored by Scott Stacey, Associate Director of PwC Australia, also an economist with substantial expertise in regulatory matters. A short biography for each of Jeff, Greg, and Scott is attached as appendix A.

The authors also wish to acknowledge the substantial contributions of Carol Osborne, Senior Consultant of NERA Economic Consulting, and Tom Walker, Senior Consultant of PwC Australia, in the preparation of this report.

1.2. Terms of reference

The ENA has asked us to report on two separate matters relating to expenditure forecasts and capital and operating expenditure incentives. Our terms of reference with respect to expenditure forecasts was to prepare a joint expert report with the following coverage.

In relation to the question raised in the AEMC's Directions Paper[4] (Directions Paper) as to whether those features of the National Electricity Rules (NER or Rules) that are designed to be consistent with the 'policy intent' as described in the AEMC's original rule determination for Chapter 6A[5] of the NER:

- review the considerations that the AEMC indicated were the policy intent of the Chapter 6A framework at the time it was established in 2005-06;
- review the extent to which this policy intent has been given effect or applied by the AER; and
- consider whether the process by which a regulatory determination begins with and maintains as its fundamental reference point the submission of an expenditure proposal by the service provider continues to reflect best practice regulation, by reference to regulatory principles and practice as applied in:

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4 AEMC*, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* Directions Paper, March 2012, page 30, question 3.

5 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006), page 30.

  - the United Kingdom (following the RIIO);
  - New Zealand, under the Default Price Path (DPP) and Customised Price Path (CPP)regime; and
  - the United States, where the process begins with a service provider filing a 'rate case'.

In relation to capital and operating expenditure incentives our terms of reference was to describe and analyse:

- the incentives that already apply in the Rules for operating expenditure to be efficient;
- whether a symmetric capital expenditure incentive scheme – which was proposed in the previous joint expert report[6] (JER) on capital expenditure incentives – remains appropriate, and to provide an evaluation of the AER's arguments for an asymmetric scheme;
- in view of the conclusions above and the previous JER, what criteria are recommended to inform the implementation and design of an efficiency benefits sharing scheme (EBSS); and
- whether, and in what circumstances, actual depreciation rather than forecast depreciation should be applied when updating the regulatory asset base at the commencement of a regulatory period.

1.3. Structure of the remainder of this report

This report is structured as follows:

- section two introduces the relevant claims made by the AER and the questions raised by the AEMC regarding the policy intent of Chapter 6A. This is followed by a discussion of the context that is likely to have influenced the AEMC's approach to the review of the Rules for the economic regulation of transmission networks;
- section three explains the role of 'guided discretion' and its application by the AER in making its decisions and provides a review of whether the policy intent of Chapter 6A reflects international best practice;
- section four analyses the extent to which the expenditure assessment framework under the Chapter 6A Rules has been interpreted and applied;
- section five identifies what incentives apply under the Rules for efficient operating expenditure and discusses how incentives can be applied to capital expenditure; and
- section six sets out the criteria that we consider should be applied for the design and implementation of an ex-post prudence test, were such a test introduced.

6 NERA/Gilbert+Tobin/PWC, *Design of Capital Expenditure Incentive Arrangements*, December 2011.

2. Chapter 6A and Policy Intent

This section introduces the relevant claims made by the AER and the questions raised by the AEMC regarding the policy intent of Chapter 6A. This is followed by a discussion of the context that is likely to have influenced the AEMC's approach to the review of the Rules for the economic regulation of transmission networks.

2.1. Claims made by the AER

In its rule change proposal, the AER contends that the requirement upon it to start from the NSP's regulatory proposal and then accept the expenditure forecast component if it is satisfied that this forecast 'reasonably reflects' the operating expenditure criteria allows network businesses to propose 'the highest possible forecast'.[7] Further, the AER contends that this leaves the evidentiary burden on it to prove that the proposed forecast is neither efficient nor prudent.

The AER contends that it is restricted in its ability to determine a substitute expenditure forecast and, in particular, is excluded from setting a different, lower forecast that would also satisfy the revenue and pricing principles in the National Electricity Law (NEL).[8] The AER also states that the prescription in the current Rules places 'significant limitations on the regulatory judgement that can be exercised relative to what was previously available to jurisdictional regulators and the ACCC'.[9]

In its recent Directions Paper the AEMC stated that the analysis of the data and submissions does not support the AER's claim that it has been limited in its assessment of capital and operating expenditure proposals under the Rules.[10] In analysing this issue the AEMC refers to the 'policy intent' as being that set out in the Chapter 6A rule determination and described in section 3.2.2 of its Directions Paper.[11] In the Directions Paper, the AEMC expressed the view that:[12]

> '[t]he policy intent, as set out in the Chapter 6A rule determination and described in section 3.2.2 above, appears to remain appropriate and applicable.'

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7 AER, *Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules*, September 2011, page 25.

8 *ibid*.

9 *ibid*.

10 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* Directions Paper, March 2012, page 29.

11 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* Directions Paper, March 2012, page 28.

12 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 28.

Statements made by the AEMC in section 3.2.2 set out its understanding of the current Rules:[13]

> '[t]he key decision-making requirement, which is very similar for Chapters 6 and 6A and for capex and opex, is that the AER must start from the NSP's regulatory proposal and must accept a capex or opex forecast if it is satisfied the total forecast reasonably reflects the relevant criteria, taking into account the relevant factors.'

And further:[14]

> '[t]he Chapter 6A rule determination contains useful explanatory material in respect of the decision-making requirement. The AEMC stated that it intended that the AER would not be "at large" in being able to reject a TNSP's forecast and replace it with its own, and that the AER must have regard to the information in the NSP's regulatory proposal. This is an important point of policy made clear by the AEMC; the NSP's regulatory proposal is the AER's starting point and represents the most significant evidentiary consideration for the AER. The constraint on the AER's power of substitution is that the substitute meet the test of efficiency, prudency, and a realistic expectation of cost inputs. At the time of making Chapter 6A, the AEMC did not think that expenditure forecasts could be specified with precision; meaning that there is no best or correct figure. At the same time though, the AEMC did not intend that the NER contemplate a range of permissible outcomes such that there could be a bias towards a higher amount. The AEMC specifically avoided referring to a reasonable estimate, or imposing a legal burden of proof.'

The AEMC seeks confirmation that the policy intent established as part of the Chapter 6A rule determination is still an expression of good regulatory practice.[15] Specifically, the AEMC poses the following questions for further comment:[16]

Question 3 Would it be appropriate for the wording of the NER to be clarified to better reflect the policy intent?

Question 6 What factors or features of the approaches of other regulators should be taken into account when reviewing other regimes to confirm the best practice approach to economic regulation?

Before we consider these questions in more detail, we consider the context within which the AEMC undertook its previous review of the Rules for the economic regulation of transmission networks.

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13 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 15.

14 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 16.

15 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 28.

16 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 30.

2.2. Context for the current 6A Rules

A number of contextual factors are likely to have influenced the AEMC's approach to the review of the Rules for the economic regulation of transmission networks. It is therefore helpful to reflect on these so that the decisions made by the AEMC at the time can be considered in their proper context. In our opinion, factors relevant to the AEMC's decision making at the time included:

- the regulatory framework that was in place at the time the AEMC was developing the Rules;
- the policy debate on network regulation that was taking place at the time; and
- the changes that had been made to the governance arrangements in the NEM.

The remainder of this section considers each of these contextual factors.

2.2.1. Previous regulatory framework

Prior to the existing arrangements, the Australian Competition and Consumer Commission (ACCC) had responsibility for both the regulation of transmission networks as well for authorisation of the National Electricity Code (NEC), which was the precursor regulatory framework to the Rules. Given the high level nature of the NEC, the ACCC sought to develop a Statement of Principles for the Regulation of Transmission Revenues. This document was first published in draft form in 1999 (DRP). This document was subsequently applied by the ACCC in a number of revenue determinations, despite it remaining as a draft for approximately five years. Following a review of the draft principles, the ACCC published a final Statement of Regulatory Principles (SRP) in 2004. However, the draft and final regulatory principles had no status in law and so were non-binding documents on the ACCC.

Clause 6.2.4(a) of the NEC required the ACCC to set the revenue cap for each TNSP. This implied that the revenue allowance set for each business was to be based solely on the ACCC's judgement about how much revenue it considered was required for a TNSP to undertake its functions. Indeed, the arrangements did not explicitly require the ACCC to have regard to any material developed by the businesses with respect to their costs over the regulatory period. In parlance that became commonplace at the time, the previous framework could not be properly described as a 'receive-determine' framework. Notwithstanding, as a matter of practice the ACCC always commenced the process with a proposal from the relevant regulated entity.

Clause 6.2.4(c) of the NEC did require the ACCC, when determining the revenue requirements of each TNSP during the regulatory control period, to have regard to:

- the demand growth that the TNSP was expected to service;
- the service standards referred to in the NEC as applicable to the TNSP and any other standards imposed on the TNSP by any regulatory regime administered by the ACCC or by agreement with relevant network users;

- the ACCC's reasonable judgement of the potential for efficiency gains to be realised by the TNSP in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards referred to above;
- the WACC of the TNSP applicable to the relevant network service, having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to those faced by TNSPs in the provision of that network service;
- the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets subject to the provisions of clause 6.2.3(d)(4);
- any State, Territorial and Commonwealth taxes (or State or Territorial equivalent of Commonwealth taxes) paid by TNSPs in connection with the provision of transmission services;
- payments to any generators providing network support services;
- the on-going commercial viability of the transmission industry;
- the amount of any reduction in the transmission customer's Transmission Use of Services general charges and / or common service charges recovered from other transmission customers in the preceding regulatory control period that the ACCC may take into account in accordance with clause 6.5.8(e); and
- any other relevant financial indicators.

These factors primarily related to elements that may add to, or influence, costs for network businesses. However, the NEC did not provide guidance to the regulator as to whether the costs for each element should be assessed by reference to whether or not they were efficient. Although the framework did not provide such guidance, the ACCC did recognise that information asymmetry concerns meant that it was not possible for it accurately to determine the amount of revenue necessary for each business. On this matter the ACCC stated:[17]

> '[i]n practice, however, the regulator is unlikely to be able to run the business of the regulated firm better than the firm itself – the regulated firm will almost always have access to information (e.g., about the price and quality of inputs, the level or forecast level of demand, and so on) that is not available to the regulator.
>
> In the presence of this "information asymmetry", it will often be preferable for the regulator to not seek to directly control key business decisions of the regulated firm, but to leave a substantial amount of discretion to the firm, while at the same time, subjecting the firm to a system of broad financial incentives which induce the regulated firm to use that discretion to pursue desirable outcomes.'

In other words, the ACCC took the view that it would need to rely upon incentives within the regime to encourage TNSPs to reveal their efficient costs over time.

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[17] ACCC, *Draft Decision, Statement of Principles for the Regulation of Electricity Transmission Revenues – Background Paper,* August 2004, pages 17-18.

2.2.2. Policy debate

The question of the appropriate decision rule for the regulator when assessing capital and operating expenditure forecasts was a particular focus of regulatory debate around the time the AEMC developed the current Chapter 6A Rules. A focal point of the debate was whether regulators should only be required to assess whether a revenue proposal from a business was reasonable, or whether they should be allowed to substitute a business's proposed amount with an alternative 'better' value.

The Export Industry Taskforce, commenting on the issue of setting expenditure forecasts, considered that a desire amongst regulators to focus upon a first best solution was inappropriate and impacted on regulated businesses undertaking otherwise efficient investments:[18]

> '[t]he manner in which regulators have approached their task has compounded the difficulties. A quest for 'first best' solutions, combined with a focus on removing monopoly rents, has distracted from what should be the regulatory task: which is not to determine whether what has been proposed by way of access conditions is optimal, but whether it is reasonable. The search for optimality and precision in regulatory decision making has not only made the regulatory process less predictable than it should be, but has also added greatly to regulatory delay, hindering investment in infrastructure used by export industries.'

The potential for regulators to overreach was also reflected in the comments of the Productivity Commission in its review of the National Access Regime:[19]

> '… when intervention occurs, it is important that regulators are not overly ambitious in their attempts to remove monopoly rent. ... (this) means that access regulation must recognise the potential costs of a 'surgical' approach to rent removal and encourage regulators to focus on the more modest objective of reducing demonstrably large rents resulting from inefficient pricing or denial of access.'

Further, when making its recommendations with respect to the Gas Code, the Productivity Commission considered that the regulator should be required to acknowledge that a range of acceptable values exist for forecast expenditure. Its view was that the regulator should focus on whether the values proposed by a business were within that range of acceptable values. On that basis, the Productivity Commission recommended that the following general provision be included in the Gas Code: [20]

> '[t]o ensure the guidance given to regulators is consistent with recommendation 7.1, s8.6 of the Gas Code should be changed to the following:
>
> s.8.6 In view of the manner in which the Rate of Return, Capital Base, Depreciation Schedule and Non Capital Costs may be determined (in each case involving various discretions), a

[18] Export Infrastructure Taskforce, *Report to the Prime Minister,* 2005, pages 2-3.

[19] Productivity Commission 2001, *Review of the National Access Regime*, Report No.17, AusInfo, Canberra, page 94

[20] Productivity Commission, *Review of the Gas Access Regime, Inquiry Report No, 31.* 11 June 2004, page 271.

> range of values may be attributed to the Total Revenue described in section 8.4. In order to assess whether a value proposed by a Service Provider is within this range the Relevant Regulator may have regard to any financial and operational performance indicators it considers relevant in order to determine whether the level of costs nominated by the Service Provider is within the range of plausible outcomes under section 8.4 that is consistent with the pricing principles contained in section 8.1.'

It is relevant to note that a number of parties, including the Expert Panel on Energy Access Pricing, were critical of the Productivity Commission recommendation in this respect, and in particular its reference to 'a range of plausible outcomes'. The scope of a plausible outcome was considered to be particularly broad. In commenting on this issue more broadly the Expert Panel took the view that there were deficiencies with both a 'propose respond' model as well as a 'consider decide' approach.[21]

2.2.3. Governance framework and the role of the Rules

At the time it was developing the new Rules, the AEMC identified that a primary consideration was the introduction of the new institutional and governance arrangements in the NEM. The AEMC noted at the time that a central premise of the governance arrangements in the NEM is a clear separation of the Rule making and Rule administration functions between the AEMC and the AER.

The implication of this separation of Rule making and Rule administration functions was considered to be that the 'regulatory discretion' arising under the previous framework and in other jurisdictions was effectively split between two entities, namely the AEMC and the AER. The AEMC has the role of exercising its discretion through making rules and the AER exercises its discretion through the making determinations. In this context, the AEMC articulated in its 2006 Final Determination what it considered to be the role of Rules:[22]

> '[t]he role of the Rules is to provide regulators and market participants clear advance guidance about the content of the regulatory framework and how the regulatory functions should be carried out. As a result, key considerations of this review concern:
>
> − the extent to which the Rules should specify in advance (codify) the criteria, methodologies and processes to be applied by the AER; and
>
> − the extent to which the AER should have discretion over those matters in performing its regulatory functions.'

When referring to the guidance provided to it for the review in section 35 of the NEL the AEMC went onto say:[23]

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21 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

22 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) page 30.

23 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) page 31.

'[t]he Commission has interpreted this statutory guidance as requiring the development of Rules that establish clear processes for conducting regulatory reviews, a full methodology for making revenue cap determinations using a building blocks approach and appropriate criteria to inform the decision making framework for the AER.

In making Rules for this purpose, the Commission's objective has been to establish a framework for regulatory processes and decision making that provides appropriate certainty and predictability for transmission investors and users, while providing the AER with sufficient regulatory discretion and flexibility to perform its role effectively. In seeking to strike this balance the Commission has been cognisant of the view expressed in stakeholder submissions that greater clarity, transparency and predictability in the regulatory framework would improve investment confidence for TNSPs, network users and energy consumers.'

3. AEMC 6A Rule Determination

A central feature of the decision rules established by the AEMC in relation to forecasts of capital and operating expenditure was the establishment of 'guided discretion' to the regulator. The guidance provided was such that the regulator was to have regard to specific objectives and criteria, and support any decision it makes with evidence. This gave rise to the key elements of the framework for forecast expenditure, being:

- the status given to the expenditure forecast proposed by the business in the expenditure framework;
- the capacity for the AER to reject a forecast and substitute it with its own where it is not satisfied that that the total amounts reasonably reflect the expenditure criteria, taking into account the expenditure factors; and
- guidance in the Rules that directs the AER's consideration of a forecast to be based upon evidence.

The remainder of this section:

- considers the role of guided discretion and its application in the key framework elements identified above; and
- reviews whether the policy intent reflects international best practice.

3.1. Balance of prescription and discretion

In undertaking its review of the framework for the economic regulation of transmission businesses the AEMC gave considerable attention to the appropriate balance between codification in Rules versus guided discretion. The AEMC considered that the approach to forecast capital and operating expenditure was a particular aspect of the Rules that provided the AER with discretion in its decision making.

When discussing its application of the guided discretion principle, the AEMC gave particular attention to the decision framework for expenditure forecasts. Specifically, the AEMC's policy intent was that, while decision making discretion is afforded to the regulator, specific guidance is required on how that discretion is to be exercised:[24]

> '[i]n relation to these areas of regulatory discretion, the Revenue Rule also provides guidance on how the discretions are to be exercised. For instance, the approach to assessing proposed forecast operating and capital expenditure in the Revenue Rule is an example in the Rules providing appropriate decision making discretion to the regulator (given the inherent uncertainty of such forecasts) with specific guidance on how that discretion is to be exercised. In other areas where the AER is provided discretion in the exercise of its regulatory function, the Commission has sought to provide additional certainty via requirements for the regulator to consult and develop guidelines.

[24] AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) page 35.

> The Commission considers that the Revenue Rule strikes an appropriate balance between codification of methodology and decision making criteria and the exercise of guided regulatory discretion. These features of good regulatory design will, over time, increase the predictability and consistency of regulatory decision making and facilitate the promotion of the NEM objective.'

When applying guided discretion to expenditure forecasts, the AEMC's objective was to deliver a framework that reduced the scope for uncertainty and risk:[25]

> '[u]nder the current rules, the criteria for making regulatory decisions have not always been clear. How the regulator would assess submissions by the TNSPs and what sources of evidence it would use have not been expressly articulated in Rules. Therefore, in establishing a framework for the decision criteria relating to expenditure forecasts the Commission has sought to reduce the scope for uncertainty and risk in a number of areas. Through the consultation process of this Review, different stakeholder groups have emphasised that a high level of regulatory discretion and uncertainty in this area increases the risk and decreases the predictability of decisions. In addition, stakeholders consider that insufficient regulatory discretion can result in inefficient costs and prices through the increased scope for regulated businesses to benefit from their market power.
>
> The AEMC has sought to make improvements in this area by giving clear guidance to the regulator and the TNSP on the process and criteria for making decisions. In developing the decision criteria for expenditure forecasts the Commission has sought to ensure that the assessment of forecasts encourages efficiency through least cost operations and timely and prudent investment in capital.'

The AEMC further articulated its policy intent in this respect as achieving an appropriate balance between addressing the costs and inefficiencies that can result from the exercise of market power and providing incentives for TNSPs to invest and operate their networks efficiently. In this context, the AEMC recognised that regulation is a poor substitute for effective competition and that the scope for regulatory error needs to be taken into account:[26]

> '…the AEMC has concluded that further clarification of its policy intention in relation to the framework for the determination of the capital and operating expenditure forecasts in the Rules [is required].
>
> Before addressing that matter in detail, however, it is worth re-emphasising that the essence of the debate that has arisen on this issue is concerned with striking an appropriate balance between competing policy objectives and stakeholder interests that arise in the context of regulating natural monopoly infrastructure such as electricity transmission services.
>
> On the one hand, economic regulation is adopted to address the costs and inefficiencies that can result from the capacity of TNSPs to exercise market power, while at the same time

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25 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) page 43.

26 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) page 48

> providing incentives for them to invest in and operate their networks efficiently. On the other hand, economic regulation is an imperfect substitute for effective competition and the potential for regulatory error can also impose costs and inefficiencies, including in relation to the incentive and financial capacity to undertake long-term investments in transmission infrastructure.'

3.1.1. Status of the TNSP's proposal

An explicit intention of the AEMC in designing the expenditure forecasting framework was to provide a strong incentive for transmission businesses to submit well articulated and soundly based forecasts of capital and operating expenditure requirements. The objective was that the TNSP's proposal be the centre of the analysis and, given concerns about the asymmetry of information as well as the risk of regulatory error, the AEMC took the view that AER should not be permitted to develop its own forecasts without having proper regard to the proposal put forward by the business. On this matter the AEMC stated:[27]

> '[t]he Draft Rules required the TNSPs to include in their Revenue Proposals forecasts of both capital and operating expenditure for the regulatory period that they consider to be required to satisfy expected demand, to comply with applicable regulatory obligations and to maintain the reliability and security of prescribed transmission services and the transmission system. The expenditure forecasts submitted by the TNSPs were also required to comply with submission guidelines and the cost allocation methodology published by the AER.'

And, further:[28]

> '[t]he Rule continues to provide the TNSPs with the opportunity of presenting a fully developed and supported Revenue Proposal to the AER, including in relation to the purposes for which the forecast expenditure is required and the assumptions and analysis on which the forecasts are based.
>
> The requirement that TNSPs submit forecasts that comply with the AER's submission guidelines and cost allocation methodology will ensure that they provide detailed submissions in support of their forecasts, reducing substantially the risks of regulatory error associated with the regulator's information disadvantage and providing the basis for informed and meaningful participation in the decision-making process by other stakeholders. The decision-making process set out in the Revenue Rule will also reduce the incentive for TNSPs to submit forecasts which represent ambit claims. Such exaggerated forecasts would be likely to fail to satisfy the decision criteria to be applied by the AER and therefore to run the risk of being rejected and replaced by the AER with a less favourable forecast.'

27 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) page 49

28 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006) pages 52-53.

3.1.2. *Decision rule for assessing a TNSP's proposal*

The AEMC's draft rule for the assessment of forecast expenditure included a requirement that the AER must accept a proposed forecast that 'reasonably reflects' specific criteria in the Rules. However, a number of stakeholders expressed concern that this characterisation may lead to an upward bias in favour of NSPs. In response to these concerns the AEMC revised the decision criteria for determining expenditure forecasts to better reflect the policy balance it was seeking.[29] This included:

- improving the specification of the objectives of the expenditure forecasts to be incorporated into the building block methodology and applied to total operating and capital expenditure forecasts;
- clarifying the decision-making rule to provide that the AER must accept a forecast if it is satisfied that the forecast reasonably reflects efficient costs, the costs a prudent operator in the circumstances of the TNSP would require and a realistic expectation of demand and cost inputs;
- noting that it found it not to be appropriate to adopt a decision rule requiring the AER to find a TNSP's forecast 'unreasonable' before it could reject it; and
- electing not to use the language 'reasonable estimate' or 'best estimate' in its rule.

The AEMC's remarks when developing the Rules for expenditure forecasts confirm its intention as to the decision rule that the AER is to apply. Specifically, that there is no legal 'burden of proof'. Instead, the AER is required to make an assessment based on evidence and reject a proposal where it is not satisfied that it meets the criteria specified:[30]

> '[i]n formulating the Revenue Rule the Commission has been assisted by the advice of Mr Neil Williams SC and Dr Ruth Higgins in relation to the decision-making rule and criteria adopted in the Draft Rule. The Commission has not thought it appropriate for the Rule to impose a legal burden of proof in the manner that is commonly understood. The advice of Williams SC and Higgins makes it clear that no "burden of proof" arises. Of course the TNSP faces a practical hurdle that if it fails to provide sufficient information to enable the AER to be "satisfied" as to whether the proposal meets the decision rules its proposal will be rejected.'

Further, the Commission did not believe it appropriate to adopt a decision rule that required the AER to conclude that a TNSP's proposal was 'unreasonable' before it could reject it. Again the Commission was assisted by the advice of Williams SC and Higgins, which confirmed that this was not the case. Rather, the decision rule operates to require the AER to reject the TNSP's proposal if it is not satisfied that it meets the criteria specified.

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29 It is worth noting that although the Commission refers to "clarifying its policy intentions" the term "policy intentions" had not been used in its Draft Determination.

30 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18* (2006), pages 34-35.

3.1.3. Evidence based decision making

Evidence based decision making was considered to be an important aspect of the Commission's Rule. As indicated above, the AEMC sought to provide an incentive for TNSPs to put forward well articulated and evidenced based proposals. However, it also sought that the decision to be made by the AER was based on evidence, including the revenue proposal under assessment. Specifically, on the question of evidence based decision making the AEMC stated:[31]

> '[u]nder the Revenue Rule, the AER is required to exercise judgement in deciding whether it is satisfied that the forecasts reflect the specified criteria, having regard to the specified factors. However, the exercise of judgement is constrained and guided by the need to be satisfied as to the efficiency and prudency of the forecast and that cost forecasts reflect realistic expectations. In exercising its judgement the AER must also have regard to the information provided in the TNSPs proposal and other evidentiary considerations specified in the Rule. That is, the AER is not at large in being able to reject the TNSPs forecast and replace it with its own. It must also provide reasons in terms of the decision criteria and the factors for both a reject of the forecasts and their replacement with forecasts that it considers to meet the requirements of the Rule.'

In addition, the AEMC was also clear that a list of evidentiary matters were provided to guide the AER in its analysis of proposals:[32]

> '...[t]he Commission has also restructured the Rules to separately specify the evidentiary matters the AER should have regard to in undertaking its assessment including: the submissions made by the TNSP and interested parties; analysis presented by the TNSP in its proposal and by the AER itself (provided that it has been published); benchmark data; and the actual and expected expenditure of the TNSP during any preceding periods.'

3.2. Does the policy intent still reflect best practice?

In it Directions Paper, the AEMC seeks to understand whether its original policy intent still represents an expression of good regulatory practice:[33]

> '…the Commission's view is that the policy intent… appears to remain appropriate and applicable. To advance this, between now and the publication of the draft rule determination the AEMC will undertake further work to compare the policy intent in the Chapter 6A rule determination with the actual practice of other relevant regulators, including both jurisdictional regulators in Australia and overseas regulators. This is to verify that the Chapter 6A policy intent remains appropriate…The Commission is interested in

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31 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, No.18,* 16 November 2006, page 53.

32 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, No.18,* 16 November 2006, page 51.

33 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 28.

whether there are features of other regulators that might be taken into account when undertaking this review.'

The Commission draws particular attention to Ofgem, in Great Britain, and the Commerce Commission, in New Zealand, which have each completed significant reviews of their regulatory frameworks since 2006 and may therefore have altered the understanding of what constitutes best practice.

In light of the matters raised by the AER's Rule change proposal in relation to expenditure allowances, the Commission expressed interest in assessing the features of the approaches of other regulators that it may want to consider in its review of other regimes, including:

- whether other regulators begin their determinations with a review of a submission by a regulated entity;
- the recourse that other regulators have to other information sources and the relative weight they place on them, for example:
  - benchmarking; and
  - other submissions;
- the decision criteria applied by other regulators as to whether a regulated entity's submissions are rejected or accepted.

The remainder of this section provides a brief overview of the approaches of other regulators.

3.2.1. New Zealand

New Zealand's regulatory framework has recently been changed with the implementation of the *Commerce Amendment Act* 2008. This was intended to improve the regulatory framework in a number of ways, one of the key objectives being to improve the level of regulatory certainty by limiting the extent of discretion available to the Commission. The new law requires the Commission to establish regulatory methodologies, rules, processes, requirements and evaluation criteria, collectively referred to as Input Methodologies (IMs). A further objective was to improve the accountability of the Commission as most decisions were previously subject only to judicial review and not to an appeal against the substance of those decisions.

On its face, the fact that the Commission sets its own regulatory framework may appear to give it a far greater level of discretion than that of the AER. However, because the Commerce Commission effectively assumes the roles of the AEMC and the AER, the New Zealand arrangements cannot be taken to imply that the AER should be accorded a similar level of autonomy as the AEMC. In practice, the Commerce Commission has set itself rules that constrain it in ways similar to the constraints on the AER. The Commerce Commission's making of decisions in relation to IMs are also subject to the right of appeal (beyond the normal grounds of judicial review).

New Zealand DNSPs[34] have two options: the acceptance of a default price-quality path (DPP) or a customised price-quality path (CPP). The default path is a low-cost regulatory option with limited review of the actual costs of the regulated businesses. However, businesses can opt for a CPP if this better reflects the nature of their business.

At any time after a DPP is set by the Commerce Commission, a supplier that is (or is likely to be) subject to the DPP can make a proposal to the Commerce Commission for a CPP. A CPP relies on detailed submission by company, which the Commerce Commission then reviews, and in that respect involves substantially the same process and commencement with an NSP's submission as arises under the NER.

3.2.2. The United Kingdom

Although on the surface the UK regulatory regime may appear to provide Ofgem with considerable discretion that is not available to the AER, in practice the extent to which Ofgem may exercise unguided discretion is heavily constrained by the ability of NSPs to reject price control proposals and initiate a wide ranging merits review process.

Even though Ofgem effectively assumes the roles of both the AEMC and the AER, it has nevertheless set out and documented its approach to regulation. This includes through its handbook for implementing the Revenue using Incentives to Deliver Innovation and Outputs (RIIO) model. This handbook sets out how the RIIO model works in practice.

The handbook produced by Ofgem makes it clear that its assessment of required expenditure will be predominately based upon a proposal, in the form of a business plan, put forward by the regulated entity. Specifically, Ofgem states:[35]

> '[u]nder the RIIO model our assessment of the outputs that network companies are required to deliver and the associated revenue to be earned from consumers will be informed, to a large degree, by the plans put forward by network companies. In the business plans a network company will set out what it intends to deliver for consumers of network services over time and what revenue it needs to earn from existing and future consumers to ensure delivery is financed. The onus is on network companies to justify their view of required expenditure.'

Ofgem also notes that its approach should seek to provide an incentive for network companies to submit well-justified business plans. It also comments that the approach it takes to assessing a proposed forecast will be highly dependent on the quality of the proposal before it:[36]

34 Transpower, New Zealand's only electricity transmission company, has an Individual Price-Quality Path regulatory arrangement, which takes account of a number of unique challenges Transpower faces, including a large and uncertain capex program due to past under-investments and the hurdle of developing forecasting systems to meet the regulatory information requirements.

35 Ofgem, RIIO Handbook, page 47.

36 Ofgem, RIIO Handbook, page 55.

> '7.28. There are a number of reasons why a network company will have an incentive to submit a well-justified business plan:
>
> ~ it is more likely that the final price control will reflect what is in the plan;
>
> ~ the use of the Information Quality Incentive (IQI) provides a financial incentive for companies to spend the time and resources necessary to produce high quality and well-justified business plans;
>
> ~ the company is likely to be subject to less intensive scrutiny;
>
> ~ the company's price control may be set earlier than others, freeing them up to focus on delivery of network services; and
>
> ~ the company's reputation will be higher with stakeholders and Ofgem.
>
> 7.29. The onus is on the network companies to provide a well-justified case to support their proposed plans for the eight-year price control period (in a longer-term context where relevant). We discuss how we will assess plans in Chapter 8. Our starting point will be to focus on the quality of the justification and the process used to make the case. Where we are comfortable with this, our assessment of base revenue is likely to be based on a cost forecast linked to that in the business plan. The nature of the link between Ofgem's view and the company's plan will depend on how the network company responds to our concerns on elements of the plan.'

Further, as with the framework under the NER, the business plan put forward by the regulated entity, and by implication the assessment of it by the regulator, has as its key focus on primary outputs linked to objectives. On the question of how a regulated entity is to justify its required expenditure Ofgem makes the following comment:[37]

> '[w]e expect network companies to take responsibility for providing relevant information and evidence to justify their proposals on what is being delivered, how best to deliver and hence on the revenue they wish to raise from consumers. We expect the network companies to take a proportionate approach to developing their business plans, placing emphasis where it adds most value. The type and level of information required will vary by type of expenditure. For example, we might expect more specific justification and evidence for high value projects, projects where there is uncertainty about what needs to be delivered (or when), activities relating to meeting the needs of future consumers and/or new types of activities. At the other end of the spectrum, we do not expect network companies to justify every pound spend on maintenance separately. It is the overall approach or strategy to maintenance that we expect to be justified, closely linked to network risk.'

As is the case in the NER, Ofgem is also clear that it will apply a range of techniques for assessing a business plan depending on the type and quality of the information contained in that plan:[38]

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37 Ofgem, RIIO Handbook, page 48.

38 Ofgem, RIIO Handbook, page 62.

> '8.29. We will use a range of different tools to assess the base revenue requirement and elicit information about the expected efficient costs for a company to deliver primary outputs over time and long-term value for money. Our decisions on the tools to use will depend on the quality of the business plans and the specific aspects of the plans that concern us as well as the cost at stake. For example, if we are concerned about telecoms costs we may use benchmarking to get a better view of what efficient telecoms costs might be. In contrast, if we are concerned about the needs case for a particular capital investment, or indeed the design of an investment project, then using experts to assess the proposal from a detailed bottom-up perspective may be appropriate.'

3.2.3. The United States

The United States approach to the economic regulation of network service providers has evolved over many decades and is neither the product of any single regulatory body nor recorded in a single set of rules. Rather, it has evolved in the hands of multiple state and federal regulators, as well as service providers and users, with significant influence from institutional foundations such as the US constitution (which has been interpreted as establishing regulatory asset values as a form of property right) and the procedural requirements of good administrative decision making.

Although there is no one system of regulation in the United States, it does have as a strong foundation the filing of evidence (effectively, a regulatory submission) to support a 'rate case' (effectively, a request for adjusted tariffs). As a matter of principle, either a service provider or a customer representative can initiate a rate case, ie, the process whereby a service provider's tariffs are subject to regulatory review and re-determination. In practice, however, the tendency for prices to rise over time means that rate cases are generally initiated by the service provider.

Importantly, the initial filing with the relevant regulatory body becomes the reference point for the subsequent process of reviewing and testing the evidence put before it, including evidence put by user groups (known as 'interveners') or other interested parties. That process takes place in a quasi-judicial setting, involving hearings, including the cross examination of expert and fact witnesses who have attested to the information submitted. Although these processes are in many respects different from those prevailing in the UK, New Zealand and Australia, it has as a fundamentally important characteristic the procedural weight given to material submitted by the service provider, as well as any other interested party. United States regulators are certainly not 'at large' to develop and apply their own methodologies for assessing and evaluating material put before them.

4. Application of Chapter 6A and Consistency with the Policy Intent

This section takes the expenditure assessment framework under the Chapter 6A Rules and considers the extent to which these Rules have been interpreted and applied so as to be consistent with the policy intent. We note that this section draws significantly on our earlier joint report for the ENA entitled *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*.

4.1. The weight given to NSP submissions

In the course of its regulatory determinations, the AER has had a high degree of regard to the NSP's submissions, as was the intent of the Rules. However, it does not appear to be the case that the AER has found it necessary to have a greater regard to NSP submissions than was required by the AEMC's original policy intent.

In our earlier report[39] we noted that, although the AER undertook line-by-line approaches to assessment and substitution, it was also clear that its substitute value reflected a total expenditure forecast that it was satisfied reasonably reflected the expenditure criteria.

It is explicit in 6A.13.2(b) that the AER is not restricted in adopting the same methodology as that proposed by a TNSP in assessing and substituting expenditure under Chapter 6A. In particular, it is clearly open to the AER, once it has decided it is not satisfied with a TNSP's forecast, to substitute a value for total expenditure based on an approach other than a line-by-line substitution of the TNSP's own expenditure forecast, assuming that the AER could justify an alternative approach.

The evidence also shows that the AER has previously taken the view that it is not in fact restricted under 6.12.3(f) to adopting the same methodology as used by the DNSP in determining a substitute expenditure forecast. To the extent that this provision has also been subject to consideration by an external review body, the Tribunal has also concluded that clause 6.12.3(f) does not result in such a restriction.

The AER's practical application of the Rules is not consistent with its proposition that the AER has considered itself unreasonably constrained by the operation of clause 6.12.3(f)(2). Furthermore, the Tribunal's decision[40] upheld the AER's view that it was permitted under 6.12.3(f) to reject EnergyAustralia's entire methodological approach and adopt some other approach. In particular the Tribunal determined that:

> '255. The primary discretion given to the AER by cl. 6.12.3(a) is to refuse to accept or approve any element of a regulatory proposal. The AER's power to substitute an amount or value or methodology exists so that it may properly

[39] NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011, page 22.

[40] Australian Competition Tribunal, *Application by Energy Australia and Others* [2009] ACompT 8 (12 November 2009).

> perform its obligation under cl 6.12.1(4)(ii) to set an estimate of the total opex that the AER is satisfied reasonably reflects the opex criteria.
>
> 256. Once the basis of EA's approach to the assessment of maintenance costs is rejected as above, then the approach undertaken by the AER is an appropriate way to proceed. [..]'

Our earlier review[41] showed that the AER has also adopted its own in-house 'repex' model to assess DNSPs' forecasts of reliability and quality maintained (RQM) capex.[42] The AER used the repex model outputs in formulating the AER's alternative forecasts of RQM capex, in the case of the Victorian DNSPs[43] and in developing its substitute capex forecast in its draft determination for Aurora.[44]

In addition, the AER has used benchmarking to assess aspects of a DNSP's expenditure forecasts, particularly in relation to operating expenditure. The AER contends that the current Chapter 6 Rules have resulted in it being unable in practice to conduct top-down benchmarking approaches in assessing DNSP's forecast expenditure. Our previous review of the AER's distribution determinations identified that, in practice, the AER has adopted benchmarking in many cases. These are outlined in section 4.3.2 of *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*.[45]

Moreover, where the AER has indicated in its determinations that it has *not* been able to utilise benchmarking, it has identified the lack of available data as the reason for this restriction, rather than constraints imposed by the Rules. For example, in its decision for the Victorian DNSPs, the AER explicitly identified the lack of data as a factor that prevented it from undertaking a comprehensive benchmarking exercise for capital expenditure.[46]

4.2. Requirement to accept 'reasonable' forecasts

We note above that the Commission established its Rule Determination so that the wording of the Rule would, in its view, be entirely consistent with the policy intent. In our earlier report,[47] we noted that the AER does not acknowledge that, in developing the Chapter 6A Rules, the AEMC explicitly considered the issue of systemic upward bias, and the

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41 NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011, pages 33-34.

42 AER, *Victorian Electricity Distribution Network Service Providers Distribution Determination 2011–2015*, Draft Decision, June 2010, page 339.

43 AER, *Victorian Electricity Distribution Network Service Providers Distribution Determination 2011–2015*, Final Decision, October 2010, page 426.

44 AER, *Draft Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17*, Draft Decision, November 2011, page 113.

45 NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011.

46 AER, *Victorian Electricity Distribution Network Service Providers Distribution Determination 2011–2015*, Final Decision, October 2010, page 400.

47 NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011, page 15.

appropriate balance between the interests of TNSPs and network users, and between the risks and costs of market and regulatory failure. We demonstrated[48] that the AEMC was aware of the suggestion of a potential upward bias in relation to expenditure forecasts and that it saw the AER's ability to substitute its own forecast of expenditure that was less favourable to the TNSP as a key element of the framework in providing an incentive against the submission by TNSPs of inflated expenditure forecasts.

The question then becomes whether the implementation of the Rule is consistent with expectations. The AEMC put this as follows:[49]

> '[t]he AER notes that the expression "reasonably reflects" in the capex and opex criteria means that there is a range of forecasts that may meet the criteria. If a forecast falls within this range, the AER must accept it, even if there is a lower possible forecast that would satisfy the criteria. In these circumstances, the AER states, a NSP will always forecast at the top of the range, leading to inflated forecasts.'

The AEMC has stated that it was not its intent that the AER be constrained to choose the highest possible level in a range.[50]

> '[a]t the time of making Chapter 6A, the AEMC did not think that expenditure forecasts could be specified with precision; meaning that there is no best or correct figure. At the same time though, the AEMC did not intend that the NER contemplate a range of permissible outcomes such that there could be a bias towards a higher amount.'

Importantly, the evidence from the AER's determinations does not support the suggestion that it has estimated a range of acceptable forecast values or that it has been constrained under the Rules to accept an NSP's proposed total forecast amounts in circumstances in which the AER considers that the forecasts are inflated. In our earlier joint report[51] we undertook a systematic assessment of all the four electricity transmission decisions and twelve distribution determinations that had been completed by the AER under the current Chapter 6A and Chapter 6 Rules. In each case, we examined the AER's decision in relation to both operating and capital expenditure forecasts with the aim of identifying whether the AER's practical implementation of the Rules indicated that the AER was been inappropriately constrained in the manner it has submitted.

Once the AER has taken the decision not to accept a TNSP's expenditure proposal, there are no restrictions under Chapter 6A as to the extent or basis on which the AER may make any adjustment of a NSPs forecasts, other than the overarching requirement for it to be satisfied

48 NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011, pages 14-17.

49 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 17.

50 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Directions Paper, March 2012, page 16.

51 NERA/Gilbert+Tobin/PWC, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011.

that the substituted allowance meets the criteria.[52] Therefore, once the AER has decided to reject a proposal it is at liberty to replace it with a new forecast it believes to be the most appropriate, thereby eliminating the potential for any upward bias that may otherwise occur. The AER itself notes in its rule change proposal that its perception of the limit on amending a proposed forecast related only to Chapter 6.

In all of its determinations, including the four TNSP determinations, the AER has rejected the total expenditure forecasts put forward by the NSP as being above the total expenditure that reasonably reflects the expenditure criteria. As a result, the theoretical potential for an upward bias in expenditure forecasts that has been raised has not been demonstrated by actual determination outcomes over the last five years. Rather, the AER has determined in all cases that it is not satisfied that the NSP's forecast reasonably reflects the expenditure criteria and so has substituted its own forecast of total expenditure in its determination.

4.3. Conclusion

The way in which Chapter 6A has been applied by the AER appears to be completely consistent with the policy intent as set out in the AEMC's Rule Determination. In particular:

- the AER has given considerable attention to NSPs' submissions, using them as a starting point, as intended by the Commission in order to mitigate regulatory risk;
- the requirement to accept forecasts that 'reasonably reflect' the criteria has not resulted in the AER either:
  - needing to establish a range of acceptable levels for opex and capex; or
  - being forced to accept forecasts it considers inappropriately high, since in each case the AER has rejected the TNSP's forecasts, replacing them with its own forecasts; and
- although it is possible to imagine that an NSP could provide a forecast that the AER must accept as reasonable even though it may not be its preferred forecast, this has not actually happened to date, and so the extent of any risks arising remain untested.

Experience to date does not indicate any deficiency in the current Rules as they relate to the Commission's policy intent. There is no evidence to support the suggestion that the AER should be accorded a greater degree of discretion on the grounds that the existing Rules do not comply with the policy intent.

[52] Notwithstanding this absence of limitation (other than that implied by the criteria themselves) we note that, subsequent to submitting its Rule change proposal, the AER has claimed that it is subject to limitations – see Powerlink Draft Decision (November 2011), p 97-100.

5. Incentives for Efficient Capital and Operating Expenditure

The purpose of this section is to address five questions set out by the ENA, namely:

- to identify what incentives apply in the Rules for efficient operating expenditure;
- is a symmetric scheme – which was proposed in the previous JER on capital expenditure incentives – appropriate;
- what are our views on the AER's arguments for an asymmetric scheme;
- what criteria are recommended to inform the implementation and design of an EBSS; and
- whether, and in what circumstances, actual depreciation rather than forecast depreciation should be applied when updating the regulatory asset base at the commencement of a regulatory period.

The remainder of this chapter of the report addresses these questions in turn.

5.1. Incentives for efficient operating expenditure

It is the NSPs who ultimately determine whether or not efficiency gains are made. Generally speaking, making efficiency gains requires some effort on the part of an NSP. To the extent that any rewards from such efforts are taken from the NSP, these companies will have a lower incentive to engage in efficiency-enhancing activities.

The fundamental objective of an efficiency sharing scheme is to enhance a NSP's incentive to pursue efficiency gains, particularly given the periodic nature of five year price reviews and the associated discontinuities in incentives around those reviews. The benefit of enhanced, or smoothed, incentives for efficiency gains is that the cost of providing services becomes less than would otherwise be the case, which ultimately translates into lower consumer prices thereby contributing to the long term interests of consumers.

Without such a scheme, NSPs would face a diminishing incentive to initiate efficiencies in delivering opex over the course of the regulatory period. For instance, if an efficiency gain occurred in year 1, the service provider would retain the benefit of the savings in each year of the regulatory control period. However, should a saving occur in the latter years of the regulatory control period the service provider would only enjoy the benefit for the remaining years of the regulatory control period.

Clause 6A.6.5 of the NER requires the AER to develop an EBSS that provides for a fair sharing between TNSPs and transmission network users of:

- the efficiency gains derived from the operating expenditure of TNSPs for a regulatory control period; and
- the efficiency losses derived from the operating expenditure of TNSPs for a regulatory control period.

The EBSS must comply with the principles prescribed in the NER at clause 6A.6.5, namely:

- the need to provide TNSPs with a continuous incentive to reduce operating expenditure irrespective of the year the efficiency gain or loss is incurred;
- the desirability of both rewarding TNSPs for efficiency gains and penalising TNSPs for efficiency losses; and
- any incentives that TNSPs may have to inappropriately capitalize operating expenditure.

Section 6.5.8 of the NER imposes similar requirements on the AER for developing an EBSS for distribution companies, with the additional requirement that the scheme have regard to:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

Under the schemes for distribution and transmission NSPs,[53] the AER's EBSS encompasses the following main features:

- the comparison of forecast and actual opex so as to measure incremental changes in the differences in each year between those actual and forecast amounts;
- the determination of penalties/rewards based on those incremental changes, and their application of carry forward for five years;
- the operation of these arrangements on a symmetric basis, so that both positive and negative carryovers are applied in full;
- the ex post adjustment to forecast opex so as to exclude cost consequences of:
  - changes in capitalisation policy;
  - differences between forecast and outturn demand growth;
  - recognised pass through events
  - non-network alternatives (for DNSPs); and
  - any additional cost categories nominated in advance by a NSP as being 'uncontrollable' and accepted by the AER.

In regard to the EBSS for TNSPs the AER stated:[54]

> '[t]he scheme exists to give regulated monopoly businesses an incentive to respond to opportunities to achieve efficiency gains, as would otherwise occur in a competitive market. Under the ex ante regulatory framework a service provider retains the benefit (higher profits) of achieving opex outturns below the level forecast in its revenue determination. If the opex outturn exceeds the forecast, the service provider suffers an opportunity cost (profits below those implied by the revenue determination).'

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53 AER, *Electricity Transmission Network Service Providers Efficiency Benefit Sharing Scheme,* Final decision, September 2007 and AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme,* June 2008.

54 AER, *Electricity Transmission Network Service Providers Efficiency Benefit Sharing Scheme,* Final decision, September 2007, page 4.

The design of the AER's EBSS improves NSPs' incentives to seek efficiency gains in the following ways:

1. It balances the interests of the NSPs with those of users in an attempt to mimic competitive market outcomes. The AER has stated that the five year carry-over will approximate to a sharing ratio between NSPs and network users of 30:70 (30% to NSPs and 70% to users), based on the net present value of the gains/losses over time. In assessing whether this would provide a strong enough incentive to NSPs the AER noted that it would be rare for a firm operating in a competitive market to retain the benefits of efficiency gains for a period of more than five years.[55]

2. The scheme provides a continuous incentive to achieve efficiencies by allowing the NSP to retain, for a fixed period, the difference (negative or positive) between its actual and forecast operating expenditure. Any such difference arising in any year of the regulatory period is retained by the NSP and carried forward for five years following the year in which the efficiency gain or loss is incurred. In this way, the scheme encourages firms to remain efficient throughout the regulatory period.

3. The AER has committed to carrying forward the entire amount of any efficiency gain (or loss) for the specified period rather than adjusting the amount on an ad hoc basis. At the time of making its Final Decision, the AER considered whether it should retain the option of adjusting any large positive carryovers to provide a greater benefit to users. The AER determined that applying all positive carryovers minimises regulatory uncertainty for NSPs and ensures consistent and continuous incentives.

An exclusion policy helps reduce distortions to the proper working of the arrangement. This exclusion policy removes the potential for NSPs to make changes to their capitalisation policy in order to distort otherwise efficient outcomes. This is important because for the rewards implicit in the efficiency carryover to reflect the cost of providing the distribution services, it is necessary that the reported expenditure information is calculated on the same basis as the expenditure forecasts against which it is compared.

Furthermore, if it is the AER's belief that the EBSS is not operating as it should such that the incentives on the NSPs are not strong enough, it is within the AER's authority to amend the EBSS as it deems appropriate, within the constraints of the NER as outlined above.

5.2. Benefits of a symmetrical capital expenditure incentive scheme

In our previous report on capital expenditure incentives we advocated the application of a symmetric, and continuous, capital expenditure scheme in the form of an EBSS. We consider that such a scheme has a number of advantages over the present capital expenditure incentives, as well as the scheme proposed by the AER.

[55] AER, *Electricity Transmission Network Service Providers Efficiency Benefit Sharing Scheme,* Final decision, September 2007, page 12.

There are three benefits from a symmetric capital expenditure incentive:

- it allows for a constant incentive for efficiency to be provided;
- it can facilitate a better balance of incentives between capital and operating expenditure; and
- it can allow for a better alignment with service performance incentives.

5.2.1. Constant incentive for efficiency

Providing a symmetric incentive scheme allows for a continuous incentive to be provided to all NSPs, irrespective of whether they expect to underspend or overspend against their approved forecasts.

The power of the incentive in any given year under an asymmetric scheme is dependent on whether an NSP expects to under or over spend relative to their forecast. If the incentive rate varies substantially during the course of a regulatory period, then an incentive may be created for either deferring or advancing projects irrespective of the merits of doing so.

The objective of providing parties with an incentive for continuous improvement can only be met if entities that are already outperforming will receive a reward for further performance improvement. Equally, those entities that are overspending will receive a greater penalty if the gap between forecast and actual expenditure widens. This implies that an equal incentive is required for underspending as is provided for overspending.

5.2.2. Balance of incentives between capital and operating expenditure

The extent to which there is a relative preference for expenditure on capital or operating expenditure is influenced by the relative power of the incentive for each. As noted in section 5.1, an EBSS is presently applied to operating expenditure. This means that a symmetric incentive already exists for this form of expenditure. Therefore, absent a corresponding symmetric incentive for capital expenditure, it is not possible for the incentives between operating and capital expenditure to be balanced.

Applying a symmetric incentive scheme to capital expenditure can help to provide a more consistent incentive between capital and operating expenditure.

If an EBSS was applied to capital expenditure it could be aligned with operating expenditure incentives simply by setting the sharing rate at the same level as applies under the EBSS for operating expenditure. Under the present design of the EBSS for operating expenditure, this could be achieved by allowing NSPs to retain any benefit or incur a penalty from any under or overspending for a period of five years. We note that under this traditional design of the scheme, in order to provide an equal incentive in each year the carry-over period is required to be a minimum of five years.[56] Conversely, if the 'straw person' design identified in the JER was implemented this would allow any combination of incentives to be chosen. Therefore, a

[56] Given this is the typical length of the regulatory period.

lower incentive rate for both capital and operating expenditure could be applied where necessary.

5.2.3. Balance of incentives with service performance incentives and obligations

Service performance incentives seek to provide a financial reward for businesses achieving a socially desirable standard of performance and financial penalties for under-performance. Similar to the case for operating expenditure, where the power of service incentives and capital expenditure incentives are not aligned, businesses may have a preference for either more or less expenditure for improved service performance. Again, applying an EBSS to capital expenditure, and choosing the power of the incentive, allows the regulator to better calibrate the balance of incentives so that such biases do not exist or are minimised.

5.3. Response to AER arguments in support of an asymmetric scheme

In considering the issue of the application of an EBSS to capital expenditure, the AEMC has sought answers from the AER on a number of specific questions, including why an EBSS has never been applied for capital expenditure in distribution. In response, the AER put forward three reasons why it has not developed an EBSS and why an asymmetric scheme is preferred:

- the deferral of projects between regulatory periods could skew the potential benefits of the scheme in favour of NSPs;
- the main incentive problem to be remedied in relation to capital expenditure is NSPs overspending and an asymmetric scheme, as proposed by the AER, is preferable to address this problem; and
- an asymmetric scheme may better balance capital expenditure incentives with service performance incentives.

We consider that the concerns raised by the AER are not well founded. Further to this, even if the concerns were well founded, the appropriate solution would not be the introduction of an asymmetric scheme. The remainder of this section provides the reasons for this view and addresses each of the AER’s concerns in turn.

5.3.1. Incentives for inefficient deferral

The AER has noted that applying a continuous incentive rate in the form of a carry-over provides scope for businesses to be over-rewarded where projects are deferred from one period to the next.

While noting that deferrals can be efficient behaviour, the scope for inefficient deferrals is an issue that needs to be resolved when an EBSS is applied to capital expenditure. However, there are practical solutions available to fix this issue and these have been applied in jurisdictions such as the United Kingdom (by Ofgem) and South Australia (by ESCOSA). To date, however, the AER does not appear to have undertaken a fulsome investigation of the options to address the issue of inefficient deferrals under an EBSS for capital expenditure.

A capital expenditure efficiency scheme in the form of an EBSS assumes that the expenditure reduction is a reduction in expenditure forever – if a project is deferred to the next regulatory period, that is still an efficiency gain, but an adjustment is required to the basic calculation to measure the benefit properly. The problem with over-counting the benefit from project deferrals is that a perverse incentive to over-defer projects may be created (that is, an incentive issue) and it may also generate politically unsustainable windfall gains.

Note also that the incentive problem only applies where businesses have substantial discretion over the timing of investment. Given that most network businesses are subject to deterministic reliability standards and are required to undertake a regulatory investment test on significant augmentation projects, this issue is likely to be most relevant to renewal projects. The potential for augmentation projects to be deferred or brought forward – and for the efficiency gains and losses to be miscounted will also exist, but as there is no discretion there is no incentive issue.

Importantly, what is required for addressing the issue is improvement, rather than perfection. Addressing the issue requires that material inefficient deferrals are identified and adjustments made to the carry-over amount to reflect the actual or expected deferral of the asset. Alternatively the capital expenditure forecast in the future period can be adjusted (however, this second approach may conflict more generally with the revenue and pricing principles of the NEL).

In order to identify where material inefficient deferrals exist, a combination of careful scrutiny by the regulator for larger projects and benchmark analysis relating to refurbishment expenditure may be required. These approaches appear consistent with those taken in jurisdictions such as the UK by Ofgem and in South Australia by ESCOSA.

It is important to note that the issue of providing an incentive for inefficient deferral is not unique to an EBSS. The AER's proposed asymmetric scheme would also encourage substantial deferrals if a business expected otherwise to overspend. In addition, the incentive also exists to a lesser extent under the current arrangements. Given that the problem of inefficient deferrals remains with the AER scheme, in addition to the other known problems with the AER's proposed scheme, not having an EBSS would be preferable to implementing an asymmetric scheme.

5.3.2. *Objective to reduce overspending*

The AER stated in its response to the AEMC's additional questions that:[57]

57 AER, *Response to AEMC queries on AER network regulation rule change proposals*, February 2012, pages 5-6.

> '[a] key benefit of the AER's sharing mechanism is that it would only apply to networks that overspend the forecast capex. Networks that traditionally invest within the forecast would be unaffected by this mechanism.'

Contrary to the AER's view, we consider that such an outcome from an asymmetrical incentive scheme is unlikely to promote overall efficiency. As stated in the previous report on capital expenditure incentives, one of the key objectives from capital expenditure incentives should be to provide NSPs with an incentive to make efficient decisions and control costs to the extent possible. This objective should be sought irrespective of how that business has performed compared to the forecast for the regulatory period. The implication is that the chosen incentive mechanism should ensure, to the extent possible, that the payoffs under the mechanism are symmetric such that improvements are rewarded and poor performance is penalised.

The expected outcomes from a symmetrical scheme are that NSPs have an incentive to continue making efforts to reduce costs relative to the counterfactual. That is, where efficiencies are possible these should be sought out. In addition, to the extent that there is an expectation that expenditure will be higher than forecast, the level of expenditure should be contained to the extent possible. In this way NSPs would have an incentive to strive for improvement irrespective of their expectations relative to the original forecast of expenditure.

5.3.3. Consistency with service incentives and objectives

In the AER's response to the AEMC's questions it noted that an asymmetric capital expenditure incentive scheme reduced concerns with poor service performance outcomes that may arise through an EBSS. Specifically the AER stated:[58]

> '[a]dditionally, an asymmetric mechanism may better balance capex incentives with service performance incentives. That is, an asymmetric mechanism would be unlikely to incentivise NSPs to continually reduce or defer capital projects to the level that it significantly deteriorated service performance.'

With or without an EBSS, and absent any other arrangement, an incentive may exist for NSPs to avoid capital expenditure at the expense of service performance. This is because an NSP can earn additional profit by avoiding expenditure where possible. Given this natural incentive for NSPs, both administrative tools and incentive mechanisms are applied to encourage a level of service performance desired by customers.

If there are concerns that there are 'gaps' that may allow NSPs to provide a level of service lower than that desired by customers, the solution should not be to implement an asymmetric scheme. If any asymmetric scheme were implemented an NSP would still have a strong incentive to avoid expenditure for service delivery, particularly if it expected to overspend during the period. Therefore, any concern about potential 'gaps' in service

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[58] AER, *Response to AEMC queries on AER network regulation rule change proposals*, February 2012, page 6.

incentive schemes should be remedied by either resolving those gaps or by reducing the power of a symmetric incentive scheme.

It is important to note that an administrative standard, such as a reliability standard, puts a limit on the extent to which a business can reduce expenditure due to a high powered capital expenditure incentive. As a consequence, irrespective of the power of the incentive to minimise capital expenditure, NSPs will always need to incur a minimum of expenditure in order to meet their service standards and obligations.

5.4. Criteria for the development of a capital expenditure EBSS

In the previous JER on capital expenditure incentives we provided a detailed discussion of the issues that arise and need to be considered when designing a best-practice EBSS for capital expenditure. We also provided a discussion of the current criteria in Chapter 6 of the NER and identified shortcomings in those criteria. The purpose of this section is to take the discussion from our previous report further and provide our views on the appropriate criteria for a capital expenditure EBSS.

The criteria have been drafted specifically with a capital EBSS in mind and are presented in the form of drafting instructions. However, the criteria potentially could apply equally to operating expenditure, although we see no reason for the criteria to be identical between the schemes. We also note that, in practice, some of the issues that are relevant for capital expenditure schemes – like considering measures to ameliorate forecasting risk – are less pressing for an operating expenditure EBSS.

The criteria have also been developed so that they could apply equally to transmission and distribution sectors. However, it is assumed that a separate Chapter 6 and 6A will remain and hence a separate scheme would be developed for transmission and distribution. It is envisaged that the resulting schemes as implemented would vary materially between transmission and distribution sectors, reflecting the differences in the technology / cost structure, services provided and regulatory obligations between the sectors. A criterion is included at the end of the list to encourage industry specific factors to be taken into account.

We consider that the following criteria are required for the design of a best practice EBSS for capital expenditure:

1. The AER would have the discretion, but not the requirement, to implement an efficiency benefits sharing scheme for capital expenditure. If it decided to introduce such a scheme, the scheme would be required to meet the remaining criteria set out below.
2. The objective for the scheme is to share the benefits of efficiency gains in a manner that best promotes the NEO.
3. Requirement for the scheme to measure efficiency gains by comparing actual expenditure against the ex-ante forecasts, except where adjustments to actual or forecasts are authorised by this Rule.

4. Requirement that the method for identifying and rewarding / penalising efficiency gains provide, as far as practicable:
   A. a continuous incentive, defined as an incentive that is equal in each year; and
   B. rewards for improvements and penalties for a decline in efficiency, and where improvement or decline of equal size (in absolute terms) would accrue the same reward or penalty (in absolute terms).
5. Requirement for the scheme to specify, or define a method for specifying, for a particular NSP, an appropriate incentive power for the scheme, having regard to:
   A. the desirability of generating a net benefit to customers;
   B. the desirability of the scheme, in combination with other incentive arrangements and regulatory obligations, providing NSPs with an incentive to act in a manner that is consistent with the NEO (including to provide an optimal level of service and to minimise the total cost of this), taking account of:
      i. the effect of the method used to update the RAB over time on the incentives relating to capital expenditure, including the choice between forecast and actual depreciation;
      ii. the incentives relating to operating expenditure;
      iii. the breadth of financial incentives related to service performance applying to NSPs or class of NSPs and the power of the incentives in such schemes;
      iv. the breadth of the regulatory obligations (including service standards) applying to NSPs or class of NSPs; and
   C. the residual risk that is created by the scheme for NSPs after considering the effect of mechanisms contemplated in clause 5.
6. Requirement to implement measures within the scheme to the extent practicable to reduce the impact on NSPs and customers of events that are not within the full control of NSPs, including by:
   A. making adjustments to the forecast or actual expenditure for categories of expenditure to reflect, to the extent practicable, the events that occurred during a regulatory period, provided the method for doing so is defined in advance;
   B. considering whether certain classes of projects should be excluded from the scheme; and
   C. considering whether a quantitative limit should be set for the impact on NSPs and customers of the effect of differences between forecast and actual expenditure.
7. Authorise adjustments to the forecast expenditure, actual expenditure or to the calculated EBSS amounts where necessary to ensure that the calculated EBSS amounts are consistent, to the extent practicable, with rewarding or penalising NSPs for the actual change in efficiency, <u>provided that</u> the method for making such adjustments is defined in advance of the regulatory period to which the expenditure relates.

8. Requirement to consider the implementation costs of the scheme and to factor this into the design of the scheme.
9. Specification that parameters or values under the scheme may vary between NSPs or classes of NSPs over time.

The rationales for these criteria are discussed in detail below.

Criterion 1

The AER would have the discretion, but not the requirement, to implement an efficiency benefits sharing scheme for capital expenditure. If it decided to introduce such a scheme, the scheme would be required to meet the remaining criteria set out below.

As we noted in our earlier report, there are a number of practical issues that need to be addressed in order to put in place a robust capital expenditure EBSS. One such practical issue is the capacity to detect when material deferral of capital projects from one period to the next occurs. While deferring projects where possible is efficient, a simple capital expenditure EBSS would over-calculate the efficiency gain that is produced by deferring projects, which in turn has the prospect of creating a perverse incentive to defer projects across regulatory periods even where it is not efficient to do so. This prospect of encouraging inefficient behaviour can be reduced or avoided by identifying where projects have been deferred and adjusting the efficiency benefit that is carried over.

We note, however, that the AER has argued that it believes it is impossible to detect when projects are deferred across periods and as such it does not consider that a symmetric EBSS for capital expenditure is appropriate. We observe that the AER does not appear as yet to have turned its mind to how this issue may be addressed in practice, including how the UK regulators have sought to identify when material deferral of projects is occurring. However, if the AER remains of the view that it could not implement an EBSS for capital expenditure without introducing considerable distortions from efficiency, it would have the discretion not to implement an EBSS. We would highlight, however, that the criteria that we have developed for the scheme would provide the AER with an explicit power to make the necessary adjustments to the 'measured' efficiency gain.

As with other schemes the AER is required to implement, where it does decide to proceed it should be required to have regard to the specific criteria set out for the scheme. This is consistent with the AEMC's approach of guiding the discretion of the regulator on important matters of regulatory design and implementation. Importantly, these criteria purposely require either a symmetric EBSS for capital expenditure or no EBSS (that is, retaining the current arrangements). This reflects our view set out in our earlier report and summarised again in the previous section that an asymmetric capital expenditure EBSS would provide inferior incentives to those that apply at present.

Criterion 2

Objective for the scheme is to share the benefits of efficiency gains in a manner that best promotes the NEO.

We recommend replacing the current objective of allowing for a 'fair sharing' of benefits and costs with a direct reference to the NEO. This is because, while the objective of 'fair sharing' appears to draw attention to aspects of the NEO, such as promoting the long-term interests of consumers and providing incentives for efficient investment in infrastructure, concepts like 'fairness' are inherently vague and may not always guide the AER to outcomes that are consistent with the NEO. We note in particular that if such a sub-objective is to perform a useful service, it needs to be able to assist in the resolution of difficult design issues – a vague criterion like 'fair sharing' is unlikely to provide assistance in such a circumstance. However, given the AER is required to undertake its functions in accordance with the NEO this criterion may prove to be redundant. If this is the case it is preferable to remove the current sub-objective criterion entirely.

Criterion 3

Requirement for the scheme to measure efficiency gains by comparing actual expenditure against the ex ante forecasts, except where adjustments to actuals or forecasts are authorised by this Rule.

The benchmark for efficiency that is reflected in regulated prices / revenues for a regulatory period is the forecast that was accepted by the AER for the period in question. As a result, it also means that it is the only practicable benchmark for which rewards or penalties under an incentive scheme can be assessed. Requiring the scheme to measure efficiency gains against the ex-ante forecasts also means that NSPs will be able to make a normal return (all else constant) if it spends the forecast.

This criterion also notes that two exceptions to measuring gains and losses against the ex ante forecasts exist, which is where a mechanism has been put in place to attempt to lessen the impact of exogenous events on the measured efficiencies (criterion 6) and where adjustments are made in accordance with a pre-specified method to ensure an accurate measure of efficiency gains (criterion 7). These mechanisms are discussed further below.

Criterion 4

Requirement that the method for identifying and rewarding / penalising efficiency gains provide, as far as practicable:

- a continuous incentive, defined as an incentive that is equal in each year, and
- rewards for improvements and penalties for a decline in efficiency, and where an improvement or decline of equal size (in absolute terms) would accrue the same reward

or penalty (in absolute terms).

This criterion is intended to ensure that the scheme delivers two outcomes, namely:

- the incentive to make efficiency gains is the same in all years of the regulatory period; and
- the NSP faces the same incentive to make efficiency gains irrespective of whether it is expected to spend more or less than the ex ante forecasts.

Taken together, these outcomes are intended to deliver the most robust and consistent incentives for NSPs with respect to capital expenditure efficiency, including to:

- ensure that NSPs always have an incentive to strive for gains;
- avoid providing NSPs with an incentive to alter the timing of capital expenditure (that is, providing an incentive rate that varies over the regulatory period and hence provides an ability to 'arbitrage' between those incentive rates);
- provide scope for the incentives for capital expenditure efficiency and operating expenditure efficiency to be aligned – and hence an incentive to make an efficient choice between the two (including a financial incentive to choose efficiently between network and non-network options); and
- provide scope for the incentive for cost efficiency to be aligned with service incentive schemes that provide a continuous incentive to improve service performance.

Criterion 5

Requirement for the scheme to specify, or define a method for specifying, for a particular NSP, an appropriate incentive power for the scheme, having regard to:

- the desirability of generating a net benefit to customers;
- the desirability of the scheme, in combination with other incentive arrangements and regulatory obligations, providing NSPs with an incentive to act in a manner that is consistent with the NEO (including to provide an optimal level of service and to minimise the total cost of this), taking account of:
  - the effect of the method used to update the RAB over time on the incentives relating to capital expenditure, including the choice between forecast and actual depreciation;
  - the incentives relating to operating expenditure;
  - the breadth of financial incentives related to service performance applying to NSPs or class of NSPs and the power of the incentive in such schemes;
  - the breadth of the regulatory obligations (including service standards) applying to the NSP or class of NSPs; and
- the residual risk that is created by the scheme for NSPs after considering the effect of the mechanisms contemplated in clause 5.

As indicated in the previous section, the appropriate power of the incentive requires a number of different factors to be considered and potentially traded-off. For example, a well balanced package of incentives requires incentives for capital expenditure efficiency to be aligned with the rewards for other behaviour so that efficient trade-offs (for example, between capital and operating expenditure) are encouraged. Equally, the coverage of service-related measures is important – where there are 'gaps' in the regulation of service, then the incentive rate may need to be lower than otherwise to avoid encouraging cost reduction at the expense of service. The risk created by the scheme for NSPs is also an important constraint on how high powered it is possible for incentives schemes to be in practice. The purpose of this criterion, therefore, is to ensure that the AER gives explicit regard to the incentive power of the scheme and to justify its decision in that regard. More specifically, this requires the AER to consider:

- the net benefit created to customers, which requires consideration of the trade-off between the size of the gains created and the share that customers receive. A higher incentive rate (all else constant) would be expected to deliver greater overall gains, but a smaller share of the gains to customers. Whether an increase in the incentive rate is expected to deliver an increase in benefits to customers would depend upon such factors as the responsiveness of businesses to the efficiency incentive, which in turn is likely to be a function of how easy the gains are to make;
- how the capital expenditure EBSS works in combination with other incentive schemes and regulatory obligations. The desirable outcome is that NSPs have a financial incentive to optimise operating expenditure, capital expenditure and service performance. In addition, NSPs should not be encouraged to reduce cost at the expense of other dimensions of performance that are valued by customers, such as system security; and
- the fact that incentive schemes inevitably create risk for NSPs and customers and that this may place an upper limit on the acceptable power of the scheme.

Criterion 6

Requirement to implement measures within the scheme to the extent practicable to reduce the impact on NSPs and customers of events that are not within the full control of NSPs, including by:

- making adjustments to the forecast or actual expenditure for categories of expenditure to reflect, to the extent practicable, the events that occurred during a regulatory period, provided the method for doing so is defined in advance
- considering whether certain classes of projects should be excluded from the scheme, and
- considering whether a quantitative limit should be set for the impact on NSPs and customers of the effect of differences between forecast and actual expenditure.

The capital expenditure that NSPs are required to undertake in any period is affected in part by events that are either beyond the control of NSPs (for example, demand) or by factors that may not be known at the time that ex ante forecasts are made (for example, asset condition). These factors cause NSPs to bear a financial risk, reflecting the fact that more or less expenditure than forecast may be required. An inevitable consequence of strengthening the incentives for capital expenditure efficiency is that this financial risk to NSPs would increase. There is a limit in practice on the extent to which it is possible and/or desirable to increase NSPs' operating risks stemming from the need for NSPs to be in a position to attract the funds required to finance their investment programs.

However, it is possible to put in place measures that have the effect of reducing the risk that NSPs bear.

The purpose of the criterion is to direct the AER to consider whether measures can be included within the scheme to reduce the overall increase in the level of risk that NSPs would bear as a result of introducing an EBSS without compromising materially the incentives that are created. The intention of such measures is to permit a higher incentive rate than otherwise would be appropriate. The list of possible measures is not exhaustive, and includes:

- setting out a formula in advance that adjusts either the forecast or actual expenditure for categories of expenditure to reduce the effect of uncertain events (for example, adjusting the forecast of connection expenditure by the difference between the forecast and actual number of connections, multiplied by a pre-specified amount per connection);
- omitting certain projects from the scheme (which could be the contingent projects); and
- setting an overall, symmetric limit to the penalty or reward under the scheme.

As noted above, the adjustment that is authorised by such a mechanism is one of the two possible exceptions to the general principle that efficiency gains and losses be calculated by comparing actual expenditure to the ex ante forecasts.

Criterion 7

Authorise adjustments to the forecast expenditure, actual expenditure or to the calculated EBSS amounts where necessary to ensure that the calculated EBSS amounts are consistent, to the extent practicable, with rewarding or penalising NSPs for the actual change in efficiency, <u>provided that</u> the method for making such adjustments is defined in advance of the regulatory period to which the expenditure relates.

This criterion seeks to authorise changes to the EBSS calculation where necessary to ensure that the measure of change in efficiency that is reflected in the EBSS calculation as closely as practicable reflects the actual change in efficiency. This is intended to be a catch-all that would permit the AER to respond to predictable measurement challenges or issues, including:

- to attempt to ensure consistency in the dividing line between capital and operating expenditure between forecast and actual expenditure (which includes the treatment of capitalised overheads);
- to attempt to identify where capital projects reflected in one period's forecasts are deferred into the next (so that the true efficiency is a deferral of cost, rather than an avoidance);
- the treatment of changes to related party margins; and
- to permit the AER to make the EBSS conditional on NSPs meeting target levels of performance for dimensions of service that are not incorporated within formal incentive schemes or regulatory obligations.

If the AER is empowered to make such adjustments then, in order to manage risk and uncertainty, there must be a requirement for the AER to clearly define the method it will use for making adjustments prior to the commencement of the regulatory period in which the incentive will apply.

Criterion 8

Requirement to consider the implementation cost of the scheme and to factor this into the design of the scheme.

An EBSS scheme can be more or less complex and intrusive on the NSP. The purpose of this criterion, therefore, is to ensure that the AER has regard to whether the complexity and / or intrusiveness of the scheme, plus its implementation costs, will derive sufficient benefit to outweigh the costs this creates.

Criterion 9

Specification that parameters or values under the scheme may vary between NSPs or classes of NSPs over time.

The purpose of this criterion is to ensure that the AER has regard to the differences between transmission and distribution (and potentially also between NSPs within each sector) that would warrant differences in how the general principles are applied between the sectors (and possibly entities). Some of the key differences between the sectors that are relevant to the design of an EBSS for capital expenditure are:

- the breadth/coverage/strength of service incentives and obligations, with the transmission sector being different to those the distribution sector as a result of its service incentives and obligations being focused more on market outcomes; and

- the size and characteristics of projects (which affects most of the design issues for the scheme, including the risk created by a scheme), the ease of excluding projects from the scheme and the ease of identifying deferred projects.

5.5. Actual versus forecast depreciation

A particular issue that was noted in the previous JER on capital expenditure incentives was that the choice of actual depreciation rather than forecast depreciation when updating the regulatory asset base at the commencement of a regulatory period was likely to create undesirable incentives for NSPs. We noted in particular that actual depreciation was likely to:

- provide a materially higher reward for avoiding expenditure on short-lived assets than for long-lived assets, and
- cause the incentive rate for capital expenditure to decline over the regulatory period at a faster rate than is the case where forecast depreciation is used.

The first of these outcomes could cause NSPs inefficiently to prefer long-lived assets over short-lived assets where substitution is possible (which may be relevant for demand side options that require IT), as well as creating a much higher hurdle before firms would undertake expenditure on short-lived assets compared to long-lived assets, potentially dissuading efficient expenditure on short-lived assets. These perverse outcomes would continue if an EBSS was applied.

The second of these outcomes would strengthen the incentive that NSPs have to defer capital expenditure within the regulatory period. This incentive could be avoided if an EBSS was applied, but would remain a concern in the absence of an EBSS.

Given these potential incentives we took the view that the use of actual depreciation is a second best option to strengthening the incentives for efficient capital expenditure, with an EBSS for capital expenditure the preferred tool for strengthening the incentives for capital expenditure efficiency. Moreover, given the perverse incentives that the use of actual depreciation may create, the use of actual depreciation may not be appropriate even if an EBSS is not introduced.

We note, nevertheless, that if the AER finds it is unable to resolve the practical issues required to introduce an EBSS for capital expenditure, it is appropriate to ask the question of whether the use of actual depreciation should be applied as a means of strengthening the incentives for capital expenditure efficiency, notwithstanding the shortcomings.

Therefore, to the extent that there is seen to be a continued role for the application of actual depreciation, despite its known issues, we consider that this should be optional and guided by criteria in the Rules. While further analysis of potential criteria is necessary, at the outset the criteria should require that the AER:

- not apply actual depreciation if there is an EBSS for capital expenditure;

- before applying actual depreciation have regard to, amongst other things, the impact of its use on matters such as:
  - the balance of incentives between operating and capital expenditure;
  - the balance of incentives with service performance schemes; and
  - the relative incentive for expenditure on assets of differing economic lives.

Requiring the AER to have regard to (at least) these criteria will ensure that it has proper regard to the implications of applying actual depreciation.

6. Ex-post Prudence Tests

The ENA has requested advice on criteria that should be applied to ensure that an ex-post prudence test was implemented in a manner that avoided causing economic harm. In this section we first set out our view on the effectiveness of ex-post prudence tests. This is followed by a discussion of the criteria that we consider should be applied for the design and implementation of an ex-post prudence test were such a test introduced.

6.1. Effectiveness of ex-post prudence tests

The theoretical intention of an ex-post prudence test is that it will promote efficiency by giving forewarning that only investment that is deemed to be prudent (or efficient in some designs) will be rolled into the RAB. Therefore, the intention is that this will:

- discourage inefficient expenditure by NSPs as such investments will not be included in the RAB, and hence will not earn a return for NSPs; and
- allow the recovery in future regulatory periods (through a return on and return of capital) on capital expenditure that exceeded the ex ante forecast where that expenditure was efficient.

Ex-post prudence tests have been applied in a number of jurisdictions in the context of electricity network regulation. These jurisdictions include the UK, Western Australia and previously in the NEM.

Each jurisdiction has applied its ex-post prudence test differently. These differences in design and application have allowed lessons to be learned about the effectiveness of an ex-post prudence test and factors that should be taken into consideration when it is applied in a regime. The overall conclusions that can be drawn from its previous application are that:

- an ex-post prudence test is best applied as a heavy, but rarely used sanction as this can encourage businesses to have in place proper processes and risk management frameworks; and
- when poorly designed and applied, it creates considerable risk and uncertainty for businesses leading to NSPs avoiding otherwise efficient expenditure. Indeed, as the test is made more intrusive, and therefore more difficult for an NSP to meet, the potential for economic harm increases substantially.

Experience to date indicates that it has been difficult to design and implement an ex-post prudence regime that achieves the desired objectives without causing economic harm due to an inappropriate increase in risk. Indeed, it is this reason, as well as the negative impact on the effectiveness of ex-ante incentives, that led to this approach for promoting efficiency being abandoned in the NEM. Instead, as identified in the previous chapter, ex-ante incentives are often better able to deliver the desired objectives without the corresponding intrusiveness and risk of an ex-post prudence test.

6.2. Principles for the application of an ex-post prudence test

Regardless of our consideration that the use of an ex-post prudence test is not appropriate in the NEM, the AEMC may seek to progress further with the development of an ex-post prudence test. The purpose of this section is to outline the principles that the AER should have regard to should this be the case.

The principles are designed to ensure that, to the extent possible, the introduction of the scheme does not lead to outcomes that do not promote the NEO. It is relevant to note that many of the issues are interrelated, with poor design with regard to one issue exacerbating the negative impacts of poor design with regards to another issue.

6.2.1. The regulator must consider only information that a prudent NSP would have used

Requiring that the regulator consider only information that a prudent NSP would have used in making an investment decision implies:

- limiting the assessment to information that was available at the time the decisions were made, and
- further limiting the information to that which would have appeared relevant at the time.

In a well designed ex-post prudence test, the regulator takes into account only information and analysis that an NSP could reasonably be expected to have considered or undertaken at the time it undertook the investment. Clearly there will be information that will reveal itself as relevant to an investment decision after the initial decision is made. However, even the most efficient NSP could not be expected to put in place measures to provide reasonable assurance that a test that applied hindsight would be passed.

It would not be reasonable to require an NSP to consider any more information than a prudent NSP *should* have considered at the time an investment decision is made. Requiring any more information than this implies that the test is more stringent than the decision making process that would be undertaken by a prudent NSP. Therefore, an ex-post prudence test should not oblige an NSP to access *more* information than, in the test's absence, a prudent NSP would have used to make the decision whether or not to invest in a particular project at a particular time.

The AER should not, however, be bound to consider only the information and analysis that a NSP presents to them in justifying its expenditure. Imprudent NSPs may have failed to consider information or failed to undertake analysis that would reasonably have been undertaken by a prudent NSP. Furthermore, the absence of information and analysis may in itself be an indication of imprudence.

Ofgem, in the most recent gas transmission price control review for the price control period 2007-12 (TPCR4), decided to disallow expenditure on an ex post basis. In this decision Ofgem disallowed a relatively small, in the context of the entire capital expenditure program, £19m of £73m expenditure already incurred by National Grid relating to the delivery of baseline capacity at the St Fergus entry terminal. This instance, however, provides a good example of the regulator having regard only to information available at the time of the decision was made, but the business not giving proper regard to this information. In making its decision Ofgem stated:

> '[w]e do not believe that NGG [National Grid Gas] has provided adequate justification for the £73m of expenditure incurred to increase the entry capacity at St Fergus in the light of indications of demand for capacity arising from the long term entry capacity auctions. Specifically, NGG NTS [National Transmission System] did not review its initial investment decision in light of important new information at the time on the location of large new sources of gas supply. Our view is that NGG NTS ignored key information at the time and made questionable decisions in the context of the entry capacity regime which had recently been introduced. In our Updated Proposals, we considered whether this investment should be excluded from the [regulatory asset value] RAV in its entirety or should be included at a discounted value.'[59]

Notably, Ofgem has also previously commented on the negative implications of applying hindsight in an ex-post prudence test. It has noted that applying hindsight can hamper efficient investment and encourage companies to use only tried and true approaches. Specifically Ofgem stated:[60]

> '[t]he use of ex post efficiency assessment by the regulator may discourage the network company from innovation and experimentation that could otherwise reduce the company's costs in the longer term. Expenditure on failed innovation and experimentation may be perceived as wasteful with the benefit of hindsight. The prospect of ex post efficiency assessment seems likely to encourage the company to use tried and tested approaches — missing opportunities to improve practices over time and find better ways of doing things… '

It is relevant to note that the current regulatory framework already seeks to ensure that NSPs have proper regard to the information before it at the time an investment is undertaken. This is achieved through obligations to undertake planning and to apply an economic test prior to significant investments being made. The Regulatory Investment Tests in particular are a process whereby network businesses are required to identify the credible options for meeting a network need that maximises the net present value of economic benefits. This upfront assessment, and associated consultation, is a further check that NSPs have had regard to the proper information before investments is undertaken.

6.2.2. The standard should be prudence (industry standard) rather than best or frontier practice

An ex-post prudence test can focus on two levels of achievement:

- the less stringent test requires the NSP to undertake reasonable, prudent or non-reckless capital investment; or

59 Ofgem, *Transmission Price Control Review: Final Proposals*, December 2006, page 33.

60 *RPI-X@20 Emerging Thinking consultation document, Alternative ex ante and ex post regulatory frameworks*, pages 15-16, 20 Jan 2010.

- a more stringent test would require NSPs to undertake the most efficient ‘frontier’ or best practice investment.

A best practice test may have some immediate appeal to regulators and customers on the basis that NSPs should not be allowed to recover any more than the fully efficient cost of service provision. However, in practice, the perceived benefit of this approach is unlikely to outweigh its significant limitations.

The more stringent test of best or frontier practice creates a significantly higher level of uncertainty that expenditure is disallowed. This is because it is difficult, if not impossible, for a regulator to determine with certainty what best practice actually is, and expert opinion on the matter would be expected to vary. A best practice test does not take into account this difficulty but instead assumes that the opinion of the regulator (or its advisors) is precisely correct. However, regulators are often not well placed to put themselves in the place of an NSP making an investment decision. In this circumstance the risk of regulatory error would be considerable.

The consequence of the risk created by a best practice test is that there would be a materially reduced incentive to undertake investments, even when they are efficient. Such a threshold would be expected to have an even greater negative impact on the incentive to undertake discretionary investments, such as those that are justified predominately on the basis of market benefits. Ofgem also recognised this potential outcome from the application of a stringent test stating:[61]

> ‘[f]urthermore, the more aggressive the regulator is in making downward adjustments on efficiency grounds when remunerating the expenditure of the network company, the riskier it will be for the company to make investments. The network may be better off spending the minimum it can get away with. This would tend to undermine the potential benefits of this model as a means to address risks that the company does not deliver what Ofgem and customers want.’

The risk created by the higher threshold test would also mean that an NSP could never expect to make a normal return on capital when it is expected to always be 100 per cent correct in its predictions of the future and its decisions for investment. To the extent that a best practice test creates additional downside risk for NSPs, this risk would need to be compensated to ensure that NSPs are at least able to recover efficient costs. Yarrow and Decker made this point when commenting on the ex-post prudency test applied by the ERA in Western Australia:[62]

> ‘[d]isallowances based on comparisons with hypothetical, best possible outcomes could, in practice, be expected to lead to severe disincentives for investment, unless these adverse incentive effects are compensated for by some other aspect of regulatory decision making, such as a higher allowed rate of return on the (diminished) rate base. If a utility could only

61 *RPI-X@20 Emerging Thinking consultation document, Alternative ex ante and ex post regulatory frameworks*, pages 15-16, 20 Jan 2010,

62 *Report on the ERA’s draft decision on proposed revisions to the access arrangement for the south west interconnected network*, pp. 6-7, 1 September 2009, G. Yarrow and C. Decker

> earn a normal rate of return in conditions in which it was always making the best possible decisions – i.e. only if, in an uncertain and complex world it was always getting things 100% right – then, in effect, it could never expect, ex ante, to make a normal return on capital.'

While compensation could be provided to accommodate for the additional risk created by a more stringent test, this is likely to be a second best solution. This is primarily because the increase in risk to NSPs would be particularly difficult to quantify accurately. Therefore, there is considerable risk that NSPs would either be over-compensated, to the detriment of customers, or under-compensated, which would significantly constrain the ability for NSPs to attract capital for necessary network investment.

6.2.3. The regulator should be required to assess NSP's decisions, rather than benchmarking cost outcomes

An ex-post prudency test may apply to either:

- the process by which projects are selected and delivered (the internal decision making process of the business); or
- the outcomes of that process (benchmarking of cost outcomes).

There are considerable limitations to an ex-post prudency test applying to benchmark cost outcomes that mean a process based decision framework should be preferred.

Benchmarking is best applied as a comparative tool in order to draw inferences as to whether prices or cost level outcomes are consistent with outcomes from other similar businesses. However, it is essential to understand the strengths and weaknesses of benchmarking. In the utilities sector the role for benchmarking is particularly limited. This is because the cost of provision is dependent on the unique characteristics of the business such as customer density and local topography. Given these considerable differences, using benchmarking to assess the efficiency of cost outcomes would pose an unacceptable risk of error on NSPs. The extent that benchmarking should be used in an ex-post framework would be as a 'sense check' to identify where additional investigation may be warranted.

Given the considerable limitations of benchmarking in an ex-post prudence test the focus of the regulator should be on the process for making decisions. In this context the regulator should be required to have regard to:

- decisions made in the course of selecting the project; and
- decisions made in the course of delivering the project.

If an NSP followed good decision making processes, applied good governance processes, and consulted with the relevant parties, there is little more that can be asked for the business to do. Whether the outcomes of a robust decision making process lead to different outcomes than would be revealed through a benchmarking process is out of the NSP's control. Therefore, it should not be subject to this threshold in the application of an ex-post prudence test.

6.2.4. The AER should be required to demonstrate imprudence

The AER should be required to prove that expenditure was inefficient, rather than on the NSP to prove that expenditure was efficient. This creates a higher barrier for the expenditure being disallowed, reducing uncertainty and the risk of regulatory error.

Concerns about regulators relying on only limited evidence to disallow an amount of expenditure have been expressed with regard to the application of ex-post prudence tests in other jurisdictions. Yarrow and Decker undertook a review of the ERA's application of an ex-post prudence test for Western Power. In their assessment they found that the regulator's analysis was particularly arbitrary and lacked supporting information or evidence.

> '[t]he relevant judgments here are, self-evidently, arbitrary. There is no basis for the 25% figure, whose only function seems to be to make a 15% figure look reasonable (because it might have been higher). The lower bound estimate of "inefficiency" is not quantified, and is simply referred to as being (in the judgment of the ERA, but in the absence of supporting evidence) more than a nominal amount. No reason is given for the particular choice of weighted average calculation that appears to lead to 15%. And, to put matters beyond doubt, that the determination lacks substantial, supporting information/evidence is explicitly recognised by the ERA in the first sentence of paragraph 606.'[63]

While further analysis would be required to assess whether this decision was indeed arbitrary, Yarrow and Decker's analysis nevertheless highlights that a high threshold of evidence should be required before expenditure is excluded from entering the RAB. Absent of this high threshold, there is a considerable risk of arbitrary decision making. Again, the natural conclusion of a low threshold would be to dissuade NSPs from making otherwise efficient investments for fear that the regulator disallows the costs of those investments.

6.2.5. The test should only be applied where the NSP has spent more than the ex-ante forecast and be subject to a project / program materiality threshold

The application of an ex-post prudence test is a particularly costly and burdensome task. It requires a regulator, its advisors, and other interested stakeholders to undertake an assessment of detailed matters relating to particular investments undertaken by NSP. In addition, considerable effort and time would be spent by NSPs providing evidence that the decisions they made were efficient and prudent.

An ex-ante capital expenditure allowance may apply across several hundreds of capital projects. Consequently, total expenditure over a forecast amount may equally extend over potentially many tens, or even hundreds of projects. Inevitably there will be some practical issues to be resolved in implementing such a review of expenditure. This includes issues such as how to establish what projects would be subject to review, and how to ensure that such a 'partial' arrangement is not applied inappropriately.

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63 *Report on the ERA's draft decision on proposed revisions to the access arrangement for the south west interconnected network*, p. 26, 1 September 2009, G. Yarrow and C. Decker

Given the costs incurred in undertaking an ex-post assessment, its use should be limited to only those circumstances where the benefits would outweigh the costs. That is, in limited circumstances where there is potential that imprudent decisions may have been made that are material in nature.

In the United Kingdom the previous application of an ex-post prudence test has seen Ofgem focus only on individual projects within the program of works which:

- were above a threshold expenditure level of £5m; or
- had similar profiles to future capital expenditure, in order to assist other aspects of the price setting process (namely a review of forecast expenditure).

Following this high level review, Ofgem and its advisors only undertook a more detailed review of projects above a £10m value.

Applying the test to specific projects in this way means that specific instances of inefficiency can be identified while limiting the information and analytical burden on both the company and the regulator. Indeed, in application the approach undertaken by Ofgem appears to be more akin to a form of 'sense-check'. This approach recognises the difficulty for the regulator to demonstrate that expenditure has been inefficient on an ex-post basis.

6.2.6. The AER should produce a guideline setting out how it would apply the test

The risk of regulatory error, and uncertainty in the application of an ex-post prudence test, can be reduced by the regulator setting out its approach to applying the test in guidelines. The benefits of guidelines was identified by the AEMC when it developed the current Chapter 6A Rules where it stated:[64]

> '…[h]owever, the Commission has been cognisant there remain certain aspects of the regulatory framework where it would be inappropriate to fix regulatory practice in statutory rules.
>
> In these areas, the Revenue Rules provide the AER with discretion in the exercise of its regulatory function. Where this approach has been adopted, the Commission has sought to provide additional certainty to both the regulator and industry participants through a requirement for the regulator to consult and develop guidelines.'

In addition, NERA noted in the context of criticising proposals for ex-post assessments made by Frontier Economics on behalf of CE Electric in the US that:[65]

> '[t]he danger with using undefined criteria for an ex-post assessment is that it merely creates regulatory risk [and] discourages investment'.

64 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, No.18,* 16 November 2006*,* page 63.

65 NERA, *IQI Reviewed: Comments on Frontier Economics' Paper*, October 2008, page 7.

In this context, it should be noted that the more explicit the guidelines developed by the AER the greater certainty is provided to NSPs. Therefore, the Rules related to an ex-post prudence test may also seek to guide the AER on what specific matters should be addressed in a guideline.

6.2.7. The test should be linked to continued merit review of determinations (and so merit review of the test)

The risk of regulatory error is prevalent throughout the regulatory regime. The presence of an appeals mechanism within the price determination process is a means to reduce this risk.

NSPs are presently able to:

- appeal aspects of the price determination to the Australian Competition Tribunal (ACT) if they consider that the AER was unreasonable in its application of the Rules; and
- appeal aspects of the price determination in courts if they consider that the AER exceeded its remit as dictated in the Rules and Law.

If an ex-post prudence test is applied, the regime should allow for the present appeal mechanisms to extend to this test. Given the ex-post prudence test would be conducted at the time when the RAB for the next regulatory period is determined, it would be expected that the results of the test would be included as part of the regulatory determination for prices. If this is the case it would allow for the existing review process, where NSPs can select which aspects of the determination to appeal, to be applied to ex-post prudence tests.

Appendix A. Authors

Jeff Balchin is a Principal in the PwC Economics and Policy team, previously being a director of the Allen Consulting Group and prior to that in various positions in the Commonwealth Government. Jeff has over 17 years of experience in relation to economic regulation issues across the electricity, gas, airports, ports and water industries in Australia and New Zealand. He has been an adviser to governments, regulators, customers and infrastructure providers on the design, economic interpretation and application of economic regulation, which has included key roles in many of the landmark matters.

Greg Houston is a Director of NERA Economic Consulting, based in Sydney. Greg has twenty five years' experience in the economic analysis of markets and the provision of expert advice in litigation, business strategy, and policy contexts. Greg's work in the Asia Pacific region principally revolves around the activities of the enforcement and regulatory agencies responsible for competition, economic regulation and securities market matters, many of whom also number amongst his clients. In December 2005 Greg was appointed by the Hon Ian Macfarlane, then Minister for Industry, Tourism and Resources, to an Expert Panel to advise the Ministerial Council on Energy on achieving harmonisation of the approach to regulation of electricity and gas transmission and distribution infrastructure in Australia. During the 2005-06 period Greg also advised both the AEMC and the Ministerial Council on Energy on the development of the rules now applying to both the transmission and distribution network service providers.

Scott Stacey is an Associate Director of PwC. Scott specialises in the analysis of economic and regulatory issues in the utilities and infrastructure sectors, in particular, the application of incentive regulation to network businesses. He has been involved in many of the key regulatory policy debates that have taken place over recent years. Scott had a lead role in the development of the Rules for the economic regulation of transmission networks and was also involved in the development of the corresponding rules for distribution businesses. Scott joined PwC from the AEMC and has had other roles with the Network Economics Consulting Group/CRA, the Essential Services Commission in Victoria and in the Commonwealth Government's Energy Market Reform Branch.

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Attachment E

Joint Report

NERA Economic Consulting and
PwC

Attachment E – Joint Report – Trailing Average Approaches to the Cost of Debt Allowance

Trailing Average Approaches to the Cost of Debt Allowance

A joint report for the
Energy Networks Association

16 April 2012

Project Team

Jeff Balchin, Principal of PwC Australia

Greg Houston, Director of NERA Economic Consulting

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Contents

1. Introduction

This report has been jointly prepared by Jeff Balchin, Greg Houston and Brendan Quach at the request of the Energy Networks Association (ENA) for submission to the Australian Energy Market Commission (AEMC). Its subject is a description and assessment of the merits of adopting a trailing average approach to the cost of debt allowance in price and/or revenue determinations for energy network service providers (NSPs).

Our report has been prepared in light of the matters raised in the recent AEMC Directions Paper concerning rule change proposals put to the AEMC by the Australian Energy Regulator (AER) and the Energy Users Rule Change Committee (EURCC) in relation to the economic regulation of NSPs.[1]

In particular, a trailing average approach to the determination of the cost of debt allowance for privately owned electricity NSPs has been proposed by the EURCC.[2] The principal claim made by the EURCC in relation to the adoption of a trailing average is that it:[3]

> *… addresses the problem of volatile estimates of debt costs when sampled over a short period of time, and it also addresses the problem of windfall gains and losses that arise when there are differences between the embedded and future costs of debt.*

In identifying and examining the matters we have been asked to address in this report, it is also helpful to recognise the two questions posed by the AEMC in its Directions Paper, ie:[4]

> *Q.33: Is the EURCC's proposal of establishing the cost of debt using historical trailing average compatible with the overall framework for estimating a forward-looking rate of return? What are the potential benefits of using a trailing average and do they outweigh the potential costs if the estimate is less reflective of the prevailing cost of debt for NSPs?*
>
> *Q.34: What possible changes would be required in the NER to implement the EURCC's trailing average approach?*

Importantly, this report does not comment on the efficacy or otherwise of the current cost of debt benchmark. These considerations are the subject of a separate joint expert report and, for the purposes of this report, we have taken as given the current cost of debt benchmark, ie, Australian corporate debt with a BBB+ credit rating and a term to maturity of 10 years.

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1 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, Directions Paper, 2 March 2012. (Hereafter 'AEMC Directions Paper').

2 EURCC, *Proposal to change the National Electricity Rules in respect of the calculation of the Return on Debt: Proposal by Amcor, Australian Paper, Rio Tinto, Simplot, Westfarmers, Westfield and Woolworths*, 17 October 2011, page 43.

3 *ibid.*

4 AEMC, Directions Paper, 2 March 2012, pages 120 to 121.

1.1. Terms of reference

The ENA has asked us to prepare a report that:

- explains the likely ‘best practice’ approach to debt portfolio management by an infrastructure service provider operating long lived assets, but not necessarily subject to the regulation of its prices and/or revenues;
- describes the likely effects of the existing regulatory framework for NSPs (such as five yearly price/revenue determinations), conditions in the Australian corporate bond market (such as the prevalence of floating rate debt) and the implications of different ownership structures on the approach to debt portfolio management by a benchmark NSP;
- describes and assesses the distinctions and similarities between a trailing benchmark for the debt risk premium (DRP) component of the cost of debt and a trailing benchmark for the total cost of debt, as proposed to the AEMC by the Energy Users Rule Change Committee (EURCC);
- explains the methodological and measurement requirements for implementing a trailing average for any form of cost of debt allowance;
- identifies the nature and extent of the rule changes that would be necessary to give effect to such an approach, including any transitional implications; and
- offers any relevant observations on the implications of the above findings for the AEMC/AER rule change process in relation to this element of the Rate of return framework.

1.2. Authors and expertise

The authors of this report are: Jeff Balchin, Principal of PwC Australia; Greg Houston, Director of NERA Economic Consulting; and Brendan Quach, Senior Consultant of NERA Economic Consulting. Jeff, Greg and Brendan are all economists with substantial expertise in the economic regulation of network infrastructure services. A short biography for each of the authors is attached as Appendix A.

The authors also wish to acknowledge the substantial contributions of Victoria Mollard and Sarah Turner, both Analysts at NERA Economic Consulting, in the preparation of this report.

1.3. Structure of this report

The remainder of this section is structured as follows:

- Section 2 – assesses the reasons for adopting a trailing average estimate of the cost of debt;
- Section 3 – assesses the EURCC proposal for a trailing average and proposes an alternative approach to applying a trailing average that minimises the transitional issues for businesses that actively manage the risk of the current WACC framework;
- Section 4 – sets out the methodological and measurement requirements as well as implementation issues for a trailing average DRP benchmark; and
- Section 5 – concludes.

2. Assessment of a Trailing Average

A regulatory framework that establishes a cost of debt allowance that reflects as closely as practicable the debt financing practices of a benchmark efficient infrastructure service provider with long-lived assets could be expected to:

- provide NSPs a reasonable opportunity to recover at least the efficient cost of providing the regulated services; and
- reduce the extent of debt financing risks faced by an NSP, for example, by reducing the possibility that, over a particular regulatory control period, the cost of debt actually incurred by a NSP differed substantially from its cost of debt allowance.

The potential for a mismatch between the actual cost of debt and the cost of debt allowance raises the risk of investing in regulated electricity services by increasing the volatility of the returns to equity.[5] As a matter of principle, any reduction in this this risk is likely to provide a better environment for investment and so to advance the national electricity objective (NEO).

To assess whether the adoption of a trailing average approach to establishing the cost of debt allowance would reduce debt financing risk, it is helpful first to describe how an efficient NSP would finance itself, assuming it was not subject to a regime of price and/or revenue regulation.

2.1. Financing practices of efficient NSPs

Debt is used (in conjunction with equity) to finance the capital investments necessary to operate a business. The investments made by regulated energy network service providers are predominately long lived assets – by way of example, the forecast average standard life of assets in the current regulatory period for:[6]

- NSW DNSPs was 42 years;
- Vic DNSPs was 43 years;
- Qld DNSPs was 45 years;
- ETSA Utilities (SA) was 45 years;
- ActewAGL (ACT) was 44 years;
- TNSPs were 39 years.

In an ideal world a firm would seek to match the term to maturity of its debt with the economic lives of its assets. Such an approach would remove the requirement to roll over (or refinance) the debt used to finance the investment. However, the average life of NSP assets is approximately 40 years and it is generally neither possible nor economic to raise debt for

5 Where the actual cost of debt is greater than its cost of debt allowance, the profitability of the NSP will be less than the allowed return on equity. Alternatively, where the actual cost of debt is less than its cost of debt allowance, the firm's profitability will be higher than the allowed return on equity.

6 For DNSPs this is the average asset age of forecast capex weighted by forecast capital expenditure. For TNSPs a simple average of the respective weighted average standard life of the forecast capex of TransGrid, SP AusNet, AusGrid, ElectraNet, and Transend was calculated.

such terms. Consequently, NSPs must periodically roll over their debt, which gives rise to refinancing risk.[7]

Efficient firms seek to minimise refinancing risk, although it can never be completely eliminated. Refinancing risk is greatest if all debts fall due at a single point in time. Alternatively a firm can minimise refinancing risk by:

- issuing longer term debt, thereby limiting the number of occasions that debt must be rolled over; and/or
- staggering its debt maturity dates over time, thereby minimising the amount of debt that must be refinanced in any given time period.

Counterbalancing the desire for longer term debt is that borrowers generally must pay relatively higher yields for longer term debt, since investors in long dated debt forgo the potential to seek higher returns for an extended period. This was recognised by the AER in its 2009 WACC review, where it concluded that:[8]

> *network business will seek to include long term debt in their portfolios so as to mitigate refinancing risk. However, it is clear that the preference for long term debt is balanced with the competing objectives of:*
>
> - *the need to diversify across different maturities, and*
> - *minimising the overall cost of debt.*

In other words, in the absence of any regulatory distortions an efficient NSP would finance its long lived assets with a portfolio of long term debt with staggered maturity dates so as to minimise refinancing risk.

Furthermore, an efficient firm's pattern of borrowing is also likely to be influenced at the margin by fluctuations in the market cost of debt. When the cost of long term debt is thought to be relatively more expensive than shorter term debt, firms can be expected to reduce the duration of new debt raisings, and vice versa when long term debt is thought to be relatively cheap. Importantly, however, changes in the average duration of a firm's debt portfolio also bring about change to the level of refinancing risk that is being borne.

We note that some NSPs have explicit policies that serve to limit the level of refinancing risk by restricting the amount of debt maturing in any given year, ie:[9]

> *In relation to refinancing risk the Policy states that no more than 15% of the debt portfolio should mature in any one financial year.*

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7 Refinancing risk refers to the possibility that a borrower cannot repay its debt obligations when they fall due. This may occur even though the firm's assets are greater than its liabilities (ie, a positive net worth), however, the firm nevertheless cannot raise sufficient liquid funds to pay creditors as those obligations come due.

8 AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Final decision*, May 2009, page 152.

9 D. Meredith, *Statement of Gregory Damien Meredith, Treasurer for Envestra*, 2 February 2009, page 3.

The consequence of putting these principles into practice is that a firm's actual cost of debt at any point in time reflects an historical average of a portfolio of debt maturities, with tranches of this portfolio continually being refinanced at the 'spot' cost of debt.

2.2. Effect of regulation on financing practices

The NER defines the cost of debt as:

$$k_d = r_f + DRP$$

Where, pursuant to the AER's WACC Statement the risk free rate (r_f) and the debt risk premium (DRP) are estimated over a period:[10]

> *"which is as close as practically possible to the commencement of the regulatory control period".*

In other words, the current framework for measuring the cost of debt requires that the cost of debt allowance for an NSP's entire portfolio of debt be set by reference to the spot rate applying during a proximate period prior to the commencement of each regulatory period.

The debt financing strategy that would minimise the risk of an NSP's actual cost of debt varying from the regulatory allowance would involve raising (and re-raising) all of its debt finance immediately prior to the commencement of each (typically five-year) regulatory period – thereby matching the process for determining the spot allowance. However, the discussion above highlights that such a debt finance strategy would be highly risky for a stand-alone firm, since it would involve a very high degree of refinancing risk. Note that for most NSPs it would not (economically) be possible to raise sufficient debt finance within the relatively short sampling period typically accepted by the AER, which is generally in the order of 20 trading days.

A second best strategy adopted by a number of NSPs for the purpose of minimising the difference between the regulatory allowance and the actual cost of debt is to hedge the underlying or base interest rate component of the cost of debt. The market for Australian bank bill swaps (BBSW) is a reasonable (although, not perfect) market proxy for the underlying interest rate. This market is sufficiently liquid that NSPs are able:[11]

- to issue or swap the yield of their corporate debt, into the floating BBSW rate plus a fixed margin; and
- to use derivatives to fix the floating BBSW rate during the period that the risk free rate will be measured (the averaging period).

Again we note that some NSPS may not (economically) be able to undertake this second best approach due to the size of some publically owned NSPs and relatively short sampling period.

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[10] AER, *Statement of the revised WACC parameters (transmission) – Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, pages 6 and 7.

[11] See AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Final decision*, May 2009, page 144.

A consequence of such a strategy is that the NSP's interest cost at any point in time would reflect the risk free rate that was determined for the regulatory period (or, more specifically, the bank bill swap rate during the averaging period), plus a debt risk premium. The debt risk premium element would reflect the average premium across the NSP's portfolio of debt, but with this premium continually adjusting as old debt is refinanced.

Notably, NSPs are generally unable to mitigate the risk of fluctuations over time in the DRP component of the cost of debt, because the corporate debt market is insufficiently liquid to allow NSPs to hedge these risks economically.

2.3. Relative merits of a trailing average

The method applied almost universally in Australia for determining the cost of debt for regulatory purposes is to apply the spot rate of debt during a period that (in the absence of aberrant market conditions) is relatively proximate to the commencement of the new regulatory period. The analytical justification for this approach is that the on the day cost is the best estimate of the opportunity cost of debt over the regulatory period, and so, in theory, provides the greatest assurance that new capital required over the forthcoming regulatory period will be able to be financed.

However, the discussion above highlights that re-setting the cost of debt at the present day opportunity cost at each regulatory review exposes a benchmark, efficient NSP to the risk that its actual cost of debt will be materially different to the regulatory allowance. In other words, the financial risk management principle that requires an NSP to issue debt with maturities materially longer than the regulatory period and to stagger those maturities over time gives rise to an actual cost of debt for an efficient, benchmark NSP that reflects the average of historical rates. The costs arising under application of these principles is that the average of historical debt costs will almost always differ from the current spot rate.

Time-based variations in the cost of debt mean that the benchmark firm may benefit from (or wear the cost of) windfall profits (or losses) on its regulatory cost of debt allowance, as a consequence of factors that are outside of its control. It follows that the current regulatory framework gives rise to some risks for NSPs in that the profitability of the firm will vary depending on whether the regulatory determination occurs during a period for which the current cost of debt (or current DRP) is historically high or low.

The first principles justification for the use of a trailing average, therefore, is that it would reduce the prospect that the regulatory cost of debt allowance will differ to the cost of debt that an efficient, benchmark NSP would be likely to incur. Aligning the regulatory cost of debt allowance with the cost that would be incurred by an efficient, benchmark entity would increase the likelihood that an efficient, benchmark NSP would earn the allowed return on equity over the regulatory period. Such increased alignment would thereby provide a more certain investment environment and so furthering the NEO.

Further, arguably, an important motivation for the current concerns in relation to regulatory cost of debt allowances is that the spot cost of debt is at present historically high. This gives rise to regulatory allowances that can be expected to the present day actual cost of debt for a benchmark, efficient NSP. Adopting a framework that minimises the difference between debt costs and debt allowances would reduce the likelihood of this (symmetric) concern occurring in the future.

Nevertheless, we note in section 3 that adopting either of the two potential trailing average approaches would raise a number of material implementation and transitional challenges. These would need to be carefully assessed before determining whether a spot or trailing approach best meets the NEO or, alternatively, whether it is even possible to make a definitive conclusion that one approach is preferable over another.

3. Different Forms of Trailing Average

There are a number of possible forms in which a trailing average could be applied to set the regulatory cost of debt allowance. In this section we consider two possible forms of trailing average, ie:

- that proposed by the EURCC, which is to have a trailing average of the debt benchmark yield, annually updated throughout the regulatory period; and
- an alternative that reflects the current financing practices of some privately owned NSPs, which involves a trailing average of the DRP, together with a risk free rate fixed at the start of the regulatory period, also annually updated throughout the regulatory period.

Each of these approaches is considered in turn below.

3.1. EURCC proposal

Setting aside the issues raised by the EURCC on the appropriate debt benchmark, the EURCC proposed trailing average has the following features:

- a trailing average of the yield on benchmark corporate bonds, ie, an historical average of the total benchmark cost of debt, which is the sum of the risk free rate and the DRP;
- a trailing average measured over a period equal to the term to maturity of the debt benchmark; and
- the allowance for the cost of debt is recalculated each year of the regulatory control period so that the allowance incorporates debt yields in the immediately preceding year and drops data that is older that the term of the debt benchmark.

The EURCC trailing average mechanism provides a NSP with a reasonable opportunity to recover its efficient costs since the cost of debt allowance is set by reference to:

- the observed yield on benchmark debt; and
- an unbiased sample period, ie, one involving no opportunity for ‘gaming’ by either the NSP or regulator (since each ‘sample’ would be each trading day over the specified maturity).

The proposed trailing average would significantly reduce the regulatory risks associated with debt since an efficient NSP could arrange its debt financing so that it periodically issued bonds assured that the cost of debt allowance would reflect these costs.

Importantly, such a trailing average would not allow an NSP to avoid all debt financing risk because:

- it is not practicable to issue debt continuously throughout the specified maturity period, and so an NSP's debt costs will not perfectly match the debt allowance; and
- debt finance needs depend on the firm's requirements for capital, either to fund new capital expenditure (which tends to be lumpy over time) and/or to refinance existing debt.

One concern with the EURCC proposed trailing average is that its introduction would impose significant transitional issues for those NSPs that have actively and efficiently hedged their debt portfolios, ie, NSPs that have actively hedged their underlying interest rate risks by issuing (or converting to) floating rate notes whereby the borrower promises to pay a fixed margin above the floating 3 month BBSW. Such firms' existing debt obligations do not involve a fixed yield set at the time of the debt issue, but rather the cost of their debt varies over time with movements in the underlying interest rate. Some NSPs have floating rate debt maturing after 2020. Consequently, a change in the way that the cost of debt allowance is determined would undermine the NSP's hedging arrangements and potentially impose significant windfall gains or losses.

3.2. Alternative DRP trailing average

An alternative form of trailing average would be to adopt a framework that closely reflects the typical debt risk management practices of privately financed NSPs, ie:

- a trailing average benchmark DRP would be calculated over a period equal to the term to maturity of the benchmark debt;
- the DRP would be defined as the difference between the benchmark cost of floating rate debt that has the benchmark term (ie, 10 years under the current benchmark assumptions) and the 3-month BBSW;
- the benchmark DRP would be updated annually through the regulatory control period;
- a current (spot) risk free rate would be set at the start of the regulatory control period and held constant during the regulatory control period; and
- the risk free rate for debt would be set to the 5-year swap rate;

A trailing average benchmark DRP would set a cost of debt allowance that allowed an efficient NSP to avoid significant differences between its debt allowance and the cost of raising debt by adopting the current debt arrangements of some privately owned NSPs, ie:

- issue (or swap) corporate debt as a floating BBSW rate plus a fixed margin; and
- use derivatives to fix the floating BBSW rate during the period that the risk free rate is set at the time of a regulatory decision.

Again, this approach would significantly reduce debt financing risk compared with the existing framework, although again, this approach would not allow an NSP to hedge its debt costs perfectly. Nevertheless, unlike the EURCC proposal, NSPs would be able to hedge the underlying interest rate (that is, the swap rate component of the cost of debt). However, the NSP would still face the risk that its actual DRP differed materially from the benchmark, ie, where the actual margin that an NSP paid for debt issued during a year differed materially from the annual average as a result of intra-year movements in the debt risk premium. Note that under incentive-based regulation it is appropriate that NSPs be exposed to this risk to incentivise them to optimise their actual cost of capital and shield customers from inefficient financing decisions.

The possible difficulty with this approach is that some NSPs may not (economically) be able to undertake the hedging arrangements necessary to fix the floating BBSW rate during the sampling period at the time of the regulatory decision. This is primarily due to the size of some publically owned NSPs and relatively short sampling period typically accepted by the AER, which is generally in the order of 20 trading days.

4. Measurement and transitional issues

The introduction of a trailing average would involve considerable measurement issues, ie:

- the benchmark term to maturity is 10-years and so the trailing average DRP would, if calculated daily, need to be estimated around 2,500 times; and
- the estimation of the trailing average today would require estimates of either the cost of debt or DRP over the period of the GFC.

In this regard it is relevant to note that the DRP is not directly observable. Reporting agencies or bodies, such as Bloomberg and UBS, publish bond yields which are the yields that these reporting agencies or bodies estimate a particular bond would trade at if a trade was to occur on a particular day. The trading of these bonds is not reported.

Given the level of disputation associated with the measurement of the DRP over the last three years, primarily associated with the timing of the averaging period and the selection of bonds used to determine the DRP or inform its measurement, the measurement of a trailing average is likely to be a contentious process.[12] In our opinion, any new framework that introduced a trailing average should require the AER to undertake a detailed consultation process for the development of the trailing average.[13]

The introduction of any form of trailing average would represent a significant modification to the current method for setting the cost of debt allowance and so would involve a substantial change to be debt financing risk of an NSP. Such a change is likely to raise significant transitional issues for many NSPs. Therefore, it is critical that before any trailing average is introduced the AEMC/AER undertake an extensive consultation process that:

- allows all NSPs, as well as other stakeholders, to analyse the implications of adopting the new framework;
- provides an opportunity for NSPs to raise any implementation issues, specifically where the framework penalises a NSP for its current approach to mitigating debt refinancing risk; and
- develops transitional rules that allow NSPs to, where relevant, unwind current debt financing arrangements without penalty or reward.

Importantly, once a decision is made to move to a trailing average, it will become very difficult (if not impossible) to move again to a different measurement methodology. The ability to switch between setting the cost of debt allowance by reference to either a spot or a trailing average would expose NSPs and customers to regulatory “opportunism” and, in any case, the benefits of a different approach only arise if it were to remain in place over the longer term. Therefore, any change to the methodology to measure the cost of debt needs to be fully considered with all risks / benefits identified to the maximum extent possible.

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12 We note that a number of Tribunal decision on the DRP have been made over this period which would provide some guidance on the interpretation of market data.

13 We note that the Tribunal has also suggested that the AER conduct a detailed consultation on the DRP in its recent decision on the Envestra appeal - *Application by Envestra (No 2) [2012] AcompT 3 (11 January 2012)*.

Implementing a trailing average would also require significant changes to the current NER, and the AER's WACC Statement including:

- changing the definition of the risk free rate so that a different risk free rate proxy can be applied to the cost of debt allowance (ie, the 5 year swap rate) from that applied to the cost of equity (ie, 10 year Commonwealth government security yields);
- the definition of the WACC would need to be amended to incorporate the concept that the cost of debt allowance should represent the debt costs *incurred* by an efficiently financed, benchmark firm;
- the inclusion of a mechanism that would allow the DRP to be updated annually during the regulatory period, potentially through a 'cost pass through' style mechanism; and
- an instrument that ensures the measurement issues – a matter of significant controversy over the past three years – arising under the annual DRP update process are capable of being subject to merits review.

5. Conclusion

In the absence of a regulatory regime governing a firm's prices and/or revenues, an efficiently financed firm utilising long lived assets (including a regulated NSP) would periodically issue long term debt so as to minimise its refinancing risk. However, this objective would be balanced by the desirability of diversifying the timing of debt issues across time and across maturities, so as to minimise the overall, risk adjusted cost of debt.

The financing practices of NSPs are affected by the regulatory framework set out in the NER (including the AER's WACC Statement). The current cost of debt framework provides a strong incentive to refinance all debt during the averaging period immediately, so as to minimise the difference between an NSP's expected debt costs and the regulatory cost of debt allowance determined by the regulator. However, such an approach to refinancing is neither possible nor desirable for most NSPs, since it introduces an unacceptable degree of refinancing risk and, for many large NSPs, is not practicable due to their size.

An ideal regulatory framework would not distort the financing practices that would have occurred in the absence of regulation. It is likely that a well-designed trailing average would be less distortionary than the current arrangements by more closely aligning the regulatory allowance for debt with the actual costs of a NSP, although we note that these risks can never be completely extinguished.

However, the way in which a trailing average is implemented has the potential to introduce significant transitional issues affecting different NSPs, ie:

- the EURCC proposal would impose significant transitional issues for those NSPs that actively hedge interest rate risk, ie, privately owned NSPs; while
- the alternative approach could be difficult to implement for NSPs that are of such a size that they cannot economically enter the hedging market to fix the risk free rate prior to each regulatory control period.

Further, there are likely to be significant measurement issues associated with determining the historical average. These measurement issues include how historically aberrant periods should be treated (most relevantly in the current case, the period of the GFC) and the selection of the bonds whose associated reported yields would be used in the calculation of the average.

It follows from both the transitional issues and the measurement issues that would arise from a move to a trailing average method that it is critical that the AEMC/AER undertake an extensive consultation process before any decision to move to a trailing average is taken.

Appendix A. Authors

Jeff Balchin is a Principal in the PwC Economics and Policy team, previously being a director of the Allen Consulting Group and prior to that in various positions in the Commonwealth Government. Jeff has over 17 years of experience in relation to economic regulation issues across the electricity, gas, airports, ports and water industries in Australia and New Zealand. He has been an adviser to governments, regulators, customers and infrastructure providers on the design, economic interpretation and application of economic regulation, which has included key roles in many of the landmark matters.

Greg Houston is a Director of NERA Economic Consulting, based in Sydney. Greg has twenty five years' experience in the economic analysis of markets and the provision of expert advice in litigation, business strategy, and policy contexts. Greg's work in the Asia Pacific region principally revolves around the activities of the enforcement and regulatory agencies responsible for competition, economic regulation and securities market matters, many of whom also number amongst his clients. In December 2005 Greg was appointed by the Hon Ian Macfarlane, then Minister for Industry, Tourism and Resources, to an Expert Panel to advise the Ministerial Council on Energy on achieving harmonisation of the approach to regulation of electricity and gas transmission and distribution infrastructure in Australia. During the 2005-06 period Greg also advised both the AEMC and the Ministerial Council on Energy on the development of the rules now applying to both the transmission and distribution network service providers.

Brendan Quach is a Senior Consultant of NERA Economic Consulting and has eleven years of experience as an economist, specialising in network economics, and competition policy in Australia, New Zealand and Asia Pacific. Brendan specialises in regulatory and financial modelling and the cost of capital for network businesses. Brendan was involved with the initial development of the chapter 6A provisions of the national electricity rules.

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Attachment F

Farrier Swier Consulting Report

Attachment F - Farrier Swier Consulting Report – Assessment of Proposed Changes to Regulatory Process and Practice Rules

Farrier Swier
Consulting

Assessment of proposed changes to Regulatory Process and Practice Rules

Rule change request by the Australian Energy Regulator: Economic Regulation of Network Service Providers

Expert Report prepared for the Energy Networks Association

Geoff Swier, 16 April 2012

1. Introduction

1.1 Background

1. The Australian Energy Regulator (AER) lodged requests for changes to the National Electricity Rules (NER or rules) with the Australian Energy Market Commission (AEMC) on 29 September 2011 (AER Rule Change Proposal). The AER is seeking to expand its discretion for the determination of capex, opex and return on capital allowances, introduce a capex incentive scheme to penalise overspends, and increase its ability to place less weight on network services providers' (NSPs') regulatory proposals. The AEMC issued its directions paper (AEMC Directions Paper) on 2 March 2012 in which it set out its initial views. It has called for submissions by 16 April 2012.

2. I have been asked by the Energy Networks Association (ENA) to prepare an expert report examining the AER's rule change request, the ENA's submission on 8 December 2011 and the AEMC's Directions Paper. The report is to have regard to the national electricity objective and relevant extrinsic material, and provide an expert opinion on:

- the basis upon which the AEMC should determine what aspects of the regulatory process should be:
  - prescribed in the national electricity law (NEL) and/or NER
  - left to be governed by reasonable expectations of good regulatory practice
- on that basis, what changes the AEMC should make to the NER
- what supplementary protocols and/or guides the AER and NSPs can jointly develop to enhance their ability to exercise good regulatory practice.

The expert report is to examine the following regulatory process issues:

Regulatory process issues	Reference (AEMC Directions Paper)
Procedural elements of the capital and operating expenditure factors	s 3.3
NSPs’ submissions during the regulatory determination process	s 7.2
NSPs’ claims of confidentiality	s 7.3
Framework and approach paper	s 7.4
Material errors in determinations	s 7.5
Timeframes for cost pass through, contingent projects and capex reopeners	s 7.6

1.2 Experience

3. I graduated with a Masters in Commerce (Econ) from the University of Auckland in 1981. I began my career in energy sector policy and planning in 1982. Between 1994 and 1999, I assisted the Victorian Department of Treasury and Finance as deputy project leader for the reform and privatisation of the Victorian gas and electricity industries. Since that time, I have been closely involved in the establishment and operation of utility regulation in Australia. I was a founding director of Farrier Swier Consulting formed in 1999. I was a member of the Australian Energy Regulator between 2005 and 2008. I have advised regulated companies and regulators on economic regulation extensively in Australia and New Zealand.[1] Relevant experience includes being a member of three person expert panel providing advice to the Ministerial Council of Energy on definitional matters for the NEL and National Gas Law (NGR); and membership of dispute resolution panels; and provision of expert reports in economic regulation matters, arbitrations and court proceedings.

1.3 Limitations

4. This report has been prepared based on my experience as an economist practicing in economic regulation. It is not a legal interpretation of the NEL or the NER.

[1] I have provided advice and/or been a member of steering committees in relation to the following regulatory determinations: Integral Energy 2004 Electricity Distribution Price Review; Melbourne Water 2005 and 2008 regulatory submissions; TXU Networks 2005 Electricity Distribution Price Review; SP AusNet: 2010 Electricity Distribution Price Review; SP Ausnet: 2014 Gas Access Arrangement Review; Ausgrid 2014: Electricity Distribution Price Review.

1.4 Disclosure

I am a director of a company, Farrier Swier Consulting Pty Ltd (FSC) which advises governments, regulators and regulated businesses on various aspects of economic regulatory policy. FSC consultants are currently assisting the Energy Networks Association by project managing its response to the AEMC consultation on the AER proposed rule changes to the NER and National Gas Rules. Other than this expert report, I have not been involved in this work.

2. Summary

5. This section summarises this Expert Report.

On what basis should the AEMC determine what aspects of the regulatory process should be prescribed in the NEL and/or NER or left to be governed by reasonable expectations of good regulatory practice?

6. The AEMC's main focus in its original 2005 decisions on regulatory processes and practices was to ensure that the framework provides appropriate certainty and predictability for transmission[2] (and distribution) investors and users, while providing sufficient regulatory discretion and flexibility to the AER to enable it to perform its role effectively, without unnecessary rigidity. The AEMC emphasised that the regulatory costs incurred in pursuing a competitive market-like outcome may outweigh the benefits. A further principle was that increased regulatory guidance does not necessarily lead to more detailed rules - the rules can provide clear decision-making criteria on what a particular decision is intended to achieve by specifying principles to be applied or matters to be considered by the AER in making a decision. I consider this broad approach continues to be appropriate.

On what basis should the AEMC make changes to the rules?

7. Section 3.3.4 below sets out the AEMC's original policy intent for how it developed the rules. I consider that the original policy, as reflected in the AEMC's papers associated with the development of Chapter 6A, to be appropriate and to reflect principles of good regulatory practice. I am not aware of any new thinking or theory of regulation that would suggest that the policy intent to be out of date or inapplicable in 2012. Therefore I consider that any rule changes should:

[2] The AEMC's decisions on regulatory processes and practices were made as part of its review of Transmission Revenue and Pricing undertaken in 2005. Chapter 6, which was drafted by the Ministerial Council on Energy (MCE, now the Standing Council on Energy and Resources) broadly replicates the regulatory processes and practices in Chapter 6A, the MCE noting that the distribution rules largely "builds on the AEMC's approach to economic regulation of electricity transmission", see: Standing Committee of Officials of the Ministerial Council on Energy, *Changes to the National Electricity Rules to establish a National Regulatory Framework for the Economic Regulation of Electricity Distribution – Explanatory Material*, April 2007, p 5.

- involve incremental changes that do not fundamentally change the original AEMC policy intent, and
- seek to address known problems in a targeted manner, and in a way that is consistent with the original policy intent.

8. In order to provide a consistent basis for assessing each individual regulatory process issue, it is important to have clear objectives and a framework for the design of regulatory processes and practices. The following summarise the framework I propose (see section 3.4.1).

Objective	National Electricity Objective is promoted through decisions that are credible to stakeholders by reflecting principles for good regulation
Design Factors	Regulatory processes and practices should be effective in enabling information to be developed, exchanged and assessed so as to: • provide opportunities for engagement by regulated businesses and interested stakeholders • reduce regulatory risk and probability of error • promote timely decisions • facilitate reasonable administrative costs • respect legitimate commercial confidentiality.
Norms and behaviours	The design of the regulatory processes and practices should recognise the role of "norms and behaviours". Norms and behaviours work together with the NER, merits review and judicial review to help achieve the outcomes and objectives of regulatory processes and practices.
Monitoring to support evidence based review	Recognise benefits of monitoring to support improved performance of regulatory processes and practices over time.
Other instruments, guidelines and protocols	Principles of best practice regulation recognise that there can be a variety of different instruments other the rules that can be better suited to dealing with particular procedural questions.

9. An important point about this framework is that while the AEMC and the AER place considerable emphasis on "transparency", and "maximising opportunities for stakeholders to make submissions" the AEMC also recognises (and I agree) that legitimate claims for commercial confidentiality need to be respected. This leads to a conflict with principles for transparency. In my view, the ultimate test for effective regulatory processes and practices is whether they are credible with stakeholders.

10. The AEMC's original policy intent emphasises the importance of full and frank information flows and the need for effective communication between the AER and service providers. The AER has highlighted a

number of problems (or symptoms of problems) including in their view, too many late submissions, and excessive and inappropriate use of confidentiality arrangements. These problems require close attention.

11. One of the challenges for regulatory processes and practice is how to improve opportunities for better engagement by stakeholders. I have identified the following initiatives each of which would promote better engagement by stakeholders with the regulatory processes:

- Requiring the AER to publish an Issues Paper on the initial regulatory proposal (subject to assessment of administrative costs) (see section 5.3.1.1)
- Introducing a process for submissions and cross submissions on the draft decision and revised regulatory proposal (subject to assessment of administrative costs) (see section 5.3.1.2)
- Introducing a system of limited disclosure of confidential information to third parties (see section 6.4.3.4)

12. There are benefits in recognising explicitly the need to monitor the performance of regulatory processes and practices. It would be useful to set performance measures, and collect statistics on meaningful indicators of the performance of the regulatory processes.

13. There is a balance to be struck between rules and the norms and behaviours that affect the interaction between the AER and the NSPs. I consider it is too early to draw a conclusion that the balance struck in the original rules is not working effectively.

14. The AEMC note that the volume and scope of material being assessed by the AER, and consulted upon with stakeholders, has increased over time resulting in increased administrative costs. The causes of this include the merits appeal arrangements, but also the scope of information required by the AER in its Regulatory Information Notice (RIN). I consider it is not feasible for the rules to provide any further prescription to address his issue. As part of good regulatory practice it would be desirable for the AER and the NSPs to either to engage in close dialogue, or for the AER to undertake a review, so that the volume and scope of material required by the AER in the RIN or put forward by the NSPs is proportionate to the utility of the information in the regulatory process and recognises the administrative costs in incurred in collecting it.

What supplementary protocols and/or guides the AER and NSPs can jointly develop to enhance their ability to exercise good regulatory practice?

15. I recommend the AER should consult on, and issue the following Guidelines

- A Guideline on Submissions. This Guideline would codify how the AER will exercise the current rules discretion (which I recommend is retained) on how it deals with submissions (see section 5.4)

- A Guideline on Confidential Information. This Guideline would set out general principles, and definitions for common categories of legitimate confidential information (see section 6.4.3.3)

16. In developing a Guideline on Submissions there may be value in the AER consulting on, and providing guidance on areas of detail where stakeholders do not have an interest or capability in commenting and scrutinising material. This would provide added clarity in managing NSP submissions.

Procedural elements of the capital and operating expenditure factors

17. The AEMC initial position is to support an AER rule change proposal to shift so called "procedural" matters from the list of capex and opex factors in the rules to the general provisions on regulatory processes in Part E of the rules. I consider that the rules should not be changed. First, based on legal advice provided to the ENA, the AER rule change proposal could result in a significant change in the standards that apply to the AER for the analysis and justifications that need to be provided in support of AER's determinations. The rules as proposed by the AER could operate such that they require the AER to give primacy to its own analysis, relative to the weight it would be required to give to the material in a NSP's regulatory proposal. Second, a review of the original policy development process indicate that it was intended by the AEMC and policy makers that these "procedural" factors should be "fundamental elements" in the AER's decision making process. Third, the current rules are consistent with principles of good regulation for transparency and accountability.

18. The AEMC's initial position supports the AER proposal that the NER should clarify that the AER must publish its analysis within the draft or final regulatory determination, but is not obliged to do so prior to those publications. Based on legal advice provided to the ENA, I consider that AEMC's initial position is not well founded given the inconsistencies that arise between that position and the NEL.

NSPs' submissions during the regulatory determination process

19. The practice of NSPs' making submissions during the regulatory determination process is problematic because of a tension between objectives. On the one hand the objective for the AER making the best possible regulatory determination requires that it have regard to all valid information; and, on the other hand the AER has an objective of ensuring a regulatory process that is efficient, timely and transparent.

20. I disagree with the AER's proposed rule change. The AER's existing discretion as to whether or not it should have regard to submissions should be retained. I propose the following package of measures to address problems associated with new information and submissions by NSPs, and also to improve the engagement by stakeholders with the regulatory process.

    - (As noted above) the AER should consult on, and issue guidelines clarifying how it will exercise its existing rules discretion on how it may have regard to NSP submissions.

- The regulatory determination process should encourage dialogue between the AER and NSPs to establish a common understanding of the issues at the early stages of planning.
- The AER should set clear expectations as to how they intend to exercise discretion on submissions, to create clear incentives on the NSPs to provide substantially complete initial and revised regulatory proposals.
- The AER should publish an Issues Paper following receipt of the NSP's initial proposal. (This recommendation is subject to an assessment of the administrative costs). The Issues Paper content should not be binding on the AER, nor constrain its subsequent decisions.
- The AEMC should introduce a process of submissions and cross-submissions on the draft decision and revised regulatory proposal. (This recommendation is also subject to an assessment of the administrative costs).
- The AEMC should consider options for extending the regulatory period including:
  - An option to extend the current 30 business day period by an additional two weeks where it falls in this period
  - Commencing the regulatory determination process earlier
- There should be provisions to allow delay in publication of the final regulatory determination after the last material submission is received, where this is due to an "external event" and by agreement between the AER and NSP.
- (As noted above) consider requiring the AER to consult with stakeholders and perhaps develop Guidelines to identify areas of detail where stakeholders do not have an interest or capability in commenting and scrutinising material.

NSPs' claims of confidentiality

21. I agree in principle with the AEMC's initial position on the proposed rule change for dealing with NSP claims of confidentiality:

> *The NER should provide scope for as much testing and scrutiny of initial revised regulatory proposal as possible while upholding legitimate claims of confidentiality.*
>
> *There will almost always be information included as part of a NSP's initial or revised proposal which is legitimately claimed to be commercially sensitive and confidential.*
>
> *It is important that the probative value of as much of a NSP's initial or revised regulatory proposal as possible is able to be tested with stakeholders.*

22. An issue to be clarified for the AER Rule change proposal is whether discussion between the AER and NSPs could resolve the concerns, at least in part. It is unclear whether the AER has, or could in the first instance, simply approach NSPs that have 'indicated' commercial in confidence information in their

regulatory proposal to discuss whether they are prepared to provide consent to the information being released either in full or in a modified way.

23. The most important question in dealing with confidential information in my view, is, "How to facilitate an environment where the quality and relevance of probative submissions provided by stakeholders is maximised". While it is also important that stakeholders have general confidence in an open and transparent regulatory process, in my view it is important that this design feature does not limit the ability for stakeholders to provide probative submissions that are of assistance to the AER.

24. In reality, I have observed that probative information from third parties - information that can add value to the AER's scrutiny of NSP initial and revised regulatory proposals - will typically come from analysts and experts representing stakeholder groups.

25. I have undertaken a high level regulatory cost benefit analysis of 4 options to address the commercial in confidence information issue and find that the most promising option is a system for limited disclosure to third parties. This option can make available all relevant confidential information for scrutiny by stakeholders' experts, and then enable this analysis to be provided confidentially to the AER; whilst at the same time ensuing legitimate commercial in confidence information is respected.

26. I also consider there may be value in some form of codification to better define the principles and scope of legitimate confidential information. I consider the best option would be an AER Guideline (noted above). The Guideline would be developed by the AER in consultation with NSPs and stakeholders.

Framework and approach paper

27. I agree with the AEMC that if there are no material changes to all or some of components of the framework and approach paper, then it should not be necessary for there to be consultation on that particular component, and, potentially no requirement at all for any framework and approach paper.

28. In relation to incentive schemes the rules should be simplified to:

- Provide for a general review and consultation process, recognising national convergence of incentive schemes.
- Require early consultation by the AER with the NSP and also targeted stakeholder consultation to ascertain whether there is any perceived need for a review
- Create an obligation on the AER to undertake consultation on potential changes to incentive schemes if it is requested to do so by the NSP
- Enable the AER to undertake a review if it considers this would be in the long term interests of customers, taking into account the views of stakeholders, and

- Clarify that if no review is undertaken then the incentive schemes that applied in the previous regulatory period should continue in the forthcoming regulatory period

29. In regard to triggers for consultation on control mechanisms or service classifications, I propose the rules:

    - Require early consultation by the AER with the NSP and also targeted stakeholder consultation to seek views as to whether there is any need for a review of control mechanisms or service classifications.
    - Create an obligation on the AER to undertake a review if it is requested to do so by the NSP.
    - Enable the AER to undertake a review if it considers this would be in the long term interests of customers.
    - Clarify that if no review is undertaken then the control mechanisms and service classifications that applied in the previous regulatory period should continue substantially unchanged in the forthcoming regulatory period.
    - Clarify that minor changes in control mechanisms and service classifications that reflect technical considerations and do not make substantive changes can be proposed in the initial regulatory proposal or decided by the AER in the draft regulatory determination without the need for a review.

30. The AEMC requested information on how much time it is likely to take for a NSP to adjust its regulatory proposal for a revised control mechanism set by the AER in a draft regulatory determination. In my view the time that it takes a business to undertake analysis of a proposal for a revised control mechanism will vary significantly depending on the nature and extent of the proposed change. Therefore I consider that a principle-based rule be adopted that requires that, where a change is proposed, that there is early consultation between the NSP and AER at the outset of the determination process, and requires the AER and NSP to consult on and agree a decision timetable.

Material errors in determinations

31. I agree with the AEMC's initial position on objectives for material errors in determinations. A narrow approach to defining material errors helps minimise regulatory costs and creates incentives on all parties to undertake proper scrutiny of the regulatory determination process.

32. In my opinion, the AER has not made a case for its proposal to adopt a more expansive definition of "material error or deficiency".

33. I agree with the AEMC's initial view that the "only to the extent necessary" limitation should apply to false and misleading information under Chapter 6A which would align Chapter 6A with Chapter 6 and provide certainty and finality.

34. The AER proposes a rule change to enable it to ‘amend’ a distribution or transmission determination, as well as to ‘revoke and substitute’ the entire distribution or transmission determination (as currently). In my opinion, it would not be appropriate for the AEMC to make this rule change if the only, or major, effect would be to reduce rights to merits review. If AEMC investigation confirms that there are potential administrative benefits from enabling a determination to be amended, then I consider that amendment should only be allowed with the consent of the relevant NSP.

35. I agree with the AER proposal to amend rule 6A.15 to reflect the narrow scope of material errors in rule 6.13.

Timeframes for cost pass through, contingent projects and capex reopeners

36. In determining the appropriate rule design for setting timeframes for cost pass throughs, contingent projects and capex openers, I consider that the AEMC must turn its mind to fundamental design questions around managing risk and uncertainty. The challenge with rules in this area is that from time to time, exceptional circumstances may arise. On balance I am inclined to recommend a rule design where there is an expectation that the timeframes will be complied with in most circumstances, but acknowledges that there may be exceptional circumstances which mean the stated timeframe may not be able to be archived. This allows for a simpler approach to the setting of timeframes, compared to attempting to set timeframes that are workable in all circumstances.

3. Basis upon which AEMC should determine regulatory process and practices

3.1 Introduction

37. This section provides my expert opinion on

- the relevant extrinsic material (see section 3.2)
- the basis upon which the AEMC should determine what aspects of the regulatory process should be prescribed in the NEL and/or NER; or be left to be governed by reasonable expectations of good regulatory practice (see section 3.3)
- and on that basis, what changes the AEMC should make to the NER (see section 3.4).

3.2 Relevant extrinsic material

38. I consider that the appropriate extrinsic materials to review are:

- the theory of economic regulation
- principles of good regulation
- consultation requirements in the NEL
- various documents that set out how the AEMC developed its original policy intent within the framework established by the NEL in the period 2005 and 2006 (see footnotes in the next section)
- government documents on network regulation (The Expert Panel on Energy Access Pricing, Report to the Ministerial Council on Energy (2006); NERA Report to the Distribution Pricing Rule Framework, Network Policy Working Group, December 2006), and
- merits review and judicial review arrangements

3.3 Basis upon which the AEMC should determine regulatory processes

3.3.1 Theory of economic regulation

39. There is an extensive theory on economic regulation, which has influenced the development of regulatory processes in Australia. For the purpose of this report I consider it is only necessary to note discussion in the literature that highlights the overarching importance of regulatory decision-making processes being seen as credible to both consumers and investors. An authority on economic regulation, Professor David Newbury[3] [4] states:

> *"If public utilities are to be successfully privately financed, then regulation must credibly satisfy the demands both of consumers and investors. If consumers are unhappy, they cannot "exit" or choose an alternative supplier but must use their "voice" through the political process to secure their demands.... If investors are fearful for the security of future returns, they will not finance needed investment."*

3.3.2 Principles of good regulation

40. Well accepted principles of good regulation applicable to independent regulators have been identified by the OECD and the UK Better Regulation Taskforce in the following terms:[5]

- Proportionality – Regulators should only intervene when necessary. Remedies should be appropriate to the risk posed. Costs should be identified and minimised.

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[3] David Newbury in *Privatization, Restructuring and Regulation of Network Utilities*. MIT Press, Cambridge, 2000, p 29.

[4] See also Spiller, P.T. (1993): *Institutions and Regulatory Commitment in Utilities Privatization*, Industrial and Corporate Change, Vol 2, N° 3.

[5] NERA Economic Consulting, *Distribution Pricing Rule Framework: Network Policy Working Group*, December 2006 (NERA Distribution Pricing Rule Framework), p 3.

- Accountability – Regulators must be able to justify decisions and be subject to public scrutiny.
- Consistency – Government rules and standards must be joined up and implemented fairly.
- Transparency – Regulators should be open and keep regulations simple and user friendly.
- Targeting – Regulation should be focused on the problem and minimise side effects.

41. The principles of good regulation are reflected in many provisions in the NEL. Annex 1 sets out detailed analysis.

3.3.3 Consultation requirements in the NEL

42. It is relevant to note that the NEL creates obligations on the AER in relation to how it must consult with NSP's (and certain others). Subsection 16 (1) of the NEL states:

> *The AER must, in performing or exercising an AER economic regulatory function or power—*
>
> *(a) perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national electricity objective; and*
>
> *(b) if the function or power performed or exercised by the AER relates to the making of a distribution determination or transmission determination, ensure that the regulated network service provider to whom the determination will apply, any affected Registered participant and, if AEMO is affected by the determination, AEMO, are, in accordance with the rules—*
>
> *(i) informed of material issues under consideration by the AER; and*
>
> *(ii) given a reasonable opportunity to make submissions in respect of that determination before it is made.*

3.3.4 AEMC policy intent

43. The AEMC's original policy intent for regulatory processes applying to transmission networks (which processes were broadly replicated in the making of Chapter 6)[6] was set out in its 2005 Review of the Electricity Transmission Revenue and Pricing Rules. The general purposes that the AEMC considered the rules should be directed to are noted below:

- Increasing regulatory certainty through the provision of: [7]
  - clear and robust procedures, including in relation to timing and obligations on the AER;[8] and

[6] See note 2 above.

[7] AEMC, *Review of the Electricity Transmission Revenue and Pricing Rules: Consultation Program Revenue Requirements Issues Paper*, October 2005 (AEMC Consultation Program Revenue Requirements Issues Paper), p 73; AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006 (AEMC Final Rule Determination), Chapter 2 generally.

  - full disclosure of reasons for all material judgments and qualitative decisions made, options considered and all discretions exercised which have a material bearing on the outcome of a decision. [9]

- Providing clarity, certainty and consistency in the regulatory framework and its implementation by the AER to reduce regulatory risk. [10] In this regard the AEMC noted predictability and consistency is enhanced through rules, that:[11]
  - provide clear objectives and outcomes in relation to regulatory decisions;
  - provide a greater degree of guidance about the decisions to be made, and
  - set out clear procedural and informational requirements thereby increasing the transparency of decision making.
- The rules should provide an appropriate balance between decision making criteria which are prescribed /codified or flexible[12] in the context of the conferral of discretion on the AER, particularly in relation to process and procedural matters and the level of specification of methodologies.
- Noted that a codification of rules is appropriate in respect of elements of methodology and process are:
  - comparatively uncontroversial;
  - unlikely to need to vary in application across different transmission network service providers in different circumstances; or
  - necessary to be determined on an *ex ante* basis for the efficient administration of the regulatory process.[13]

44. In the process of drafting Chapter 6A the AEMC did not consider that a general principle could be applied to determine the extent of codification of rules in all circumstances; rather the extent of codification should be guided by applying a 'fit for purpose' approach. The AEMC considered that where the rules did confer

[8] AEMC Consultation Program Revenue Requirements Issues Paper, p 77; AEMC Final Rule Determination, p 31.

[9] AEMC Consultation Program Revenue Requirements Issues Paper, p 82, AEMC Final Rule Determination, pp 48-49.

[10] AEMC, *Draft Rule Determination: Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, 26 July 2006 (AEMC Draft Rule Determination), pp iii and 1; AEMC Final Rule Determination, pp iv, 33 and 108.

[11] AEMC Consultation Program Revenue Requirements Issues Paper, p 72; AEMC Final Rule Determination, pp 29, 108, 112; see also Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, (Expert Panel Report), p 59.

[12] AEMC Draft Rule Determination, pp iii, 2- 3, 7; AEMC Final Rule Determination, pp 31-35.

[13] AEMC Draft Rule Determination, p 8; AEMC Final Rule Determination, pp xix- xx.

discretion on the AER, confined criteria should govern its exercise[14] so as to provide guidance, consistency in decision making, and reasonableness in outcomes.[15]

45. The AEMC also considered that the rules should provide for mandatory procedures to promote transparency and fairness and discourage arbitrary decision making, however rigidly prescribed rules, which slow down process, prevent full and frank information flows and generally make communication between the AER and the service providers less effective should be avoided.[16]

46. I consider that the policy intent evidenced by the AEMC in the extrinsic materials associated with the making of Chapter to be appropriate and to reflect principles of good regulatory practice. I am not aware of any new thinking or theory of regulation that would suggest that the policy intent as reflected in the AEMC's papers associated with the development of Chapter 6A to be out of date or inapplicable in 2012.

3.3.5 Merits review and judicial review arrangements

47. In assessing the AER Rule Change Proposal it is also important for the AEMC to recognise the other aspects of the framework that provide avenues through which errors or defects in determinations (or the processes conducted in making those determinations), or matters that the determinations do not deal with, may be addressed. These avenues include provisions for cost pass throughs, and capex reopeners within a regulatory period, and judicial review and merits review. Merits review is available for AER network revenue or pricing determinations. Affected or interested persons or bodies may apply to the Australian Competition Tribunal (Tribunal) for review of a distribution or transmission determination. Judicial review is also available of a distribution or transmission determination made by the AER.[17]

3.4 On what basis should the AEMC make changes to the National Electricity Rules?

48. In my opinion, the AEMC's main focus in 2005 when it was developing the regulatory processes and practices in Chapter 6A (which processes and practices are largely replicated in Chapter 6) was to ensure that the framework provides appropriate certainty and predictability for transmission (and distribution) investors and users, while providing sufficient regulatory discretion and flexibility to the AER to enable it to perform its role effectively, without unnecessary rigidity.[18] The AEMC emphasised that, while the role and the extent of economic regulation should be viewed within the context of the monopoly market which has

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[14] AEMC Draft Rule Determination, p 7; AEMC Final Rule Determination, pp 31- 35.

[15] AEMC Draft Rule Determination, p 41; AEMC Final Rule Determination, pp 30-31.

[16] AEMC Consultation Program Revenue Requirements Issues Paper, p 79; NERA Distribution Pricing Rule Framework, p 4.

[17] Schedule 3, *Administrative Decisions (Judicial Review) Act 1977* (Cth).

[18] AEMC Draft Rule Determination, p 33, AEMC Final Rule Determination, p 63.

the tendency to produce social loss inefficiencies, the regulatory costs incurred in pursuing a competitive market-like outcome may outweigh the benefits.[19] A further principle guiding the AEMC's development of Chapter 6A was that increased regulatory guidance does not necessarily lead to more detailed rules - the rules can provide clear decision-making criteria on what a particular decision is intended to achieve by specifying principles to be applied or matters to be considered by the AER in making a decision.[20]

49. In my opinion the AEMC's original policy intent remains appropriate, and seems to be accepted by all parties. Therefore I consider that any further Rule changes should:

- involve incremental changes that do not fundamentally change the original AEMC policy intent, and
- seek to address known problems in a targeted manner, and in a way that is consistent with the original policy intent.

50. As noted, the AEMC's policy intent emphasises the importance of full and frank information flows and the need for effective communication between the AER and service providers. The AER has highlighted a number of problems (or symptoms of problems) including in their view, too many late submissions, and excessive or inappropriate use of confidentiality arrangements. These concerns suggest perceived or actual problems in achieving full and frank information flows and effective communication, as contemplated by the AEMC in its original policy intent. Therefore, I consider this area needs close attention in assessing potential changes to the rules. I discuss this further in section 3.4.6

51. In my view one of the challenges for improving the regulatory processes and practice is how to improve opportunities for better engagement by stakeholders, in particular organisations representing customers. As noted by the AEMC, there has been an increase in the volume and complexity of the information that must be assessed which creates real practical challenges for stakeholder organisations. I have therefore given consideration in this report to opportunities for better engagement for stakeholders. I have identified the following initiatives each of which would promote better engagement by stakeholders with the regulatory processes:

- The AER should be required to publish an Issues Paper on the initial regulatory proposal (subject to assessment of the administrative costs) (see section 5.3.1.1
- Introduce a process for submissions and cross submissions on the draft decision and revised regulatory proposal (subject to assessment of the administrative costs) (see section 5.3.1.2
- Introduce a system of limited disclosure of confidential information to third parties (see section 6.4.3.4

[19] AEMC Consultation Program Revenue Requirements Issues Paper, pp 21-22; see also Expert Panel Report, p 41.

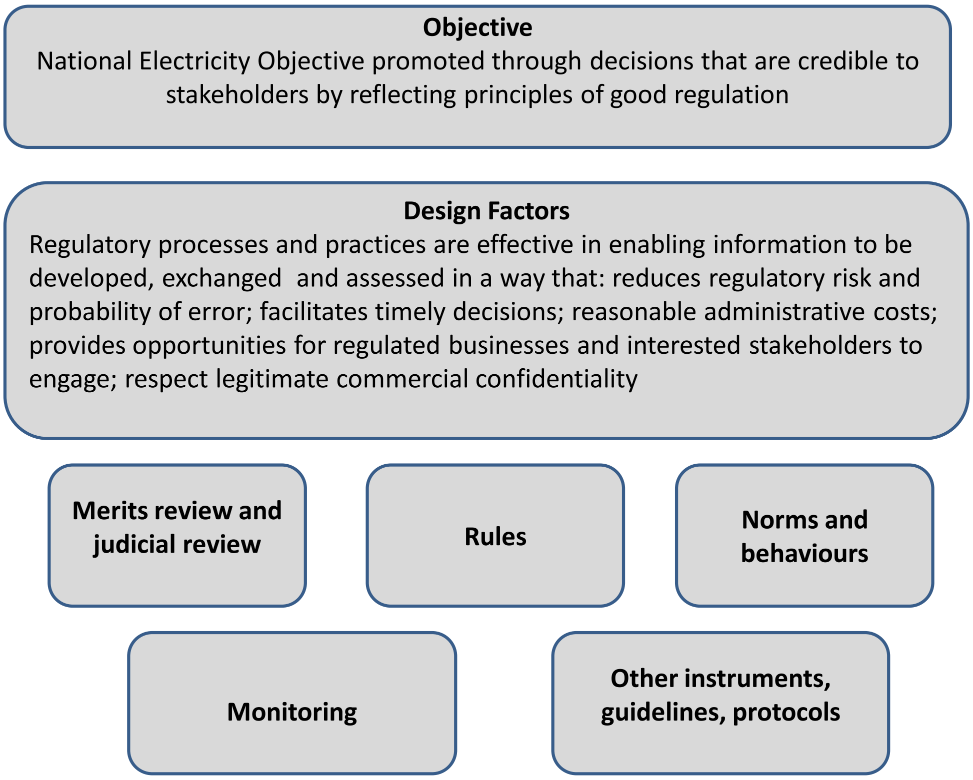
[20] AEMC Consultation Program Revenue Requirements Issues Paper, p 76; AEMC Final Rule Determination, pp 33 and 66.

52. Finally, in order to provide a consistent basis for assessing each individual regulatory process issue, it is important to have clear objectives and a framework for the design of regulatory processes and practices. This is considered in detail in the next section.

3.4.1 Objectives and framework for regulatory processes and practices

53. The following diagram summarises my proposed approach to the objectives and design of regulatory processes and practices, and the rest of this section discusses the elements of this approach.

Objectives and framework for regulatory processes and practices



54. I consider that my proposed framework is consistent with the theory of economic regulation, principles of best practice regulation, and the AEMC's policy intent as reflected in the extrinsic materials accompanying its drafting of Chapter 6A. Each element is discussed in detail below. The most important points to note are as follows.

55. First, I consider that the overarching objective for designing the regulatory processes and practices should be that the *National Electricity Objective is promoted through decisions that are credible to stakeholders by reflecting principles of good regulation*. The AEMC and the AER place considerable emphasis on "transparency", "maximising opportunities for stakeholders to make submissions" and "full and thorough"

analysis of the regulatory proposal and the regulator's decisions. The AER rule change proposals for confidential information, for example, would enable it to place greater weight on published information as compared to commercial in confidence information. But the AEMC recognises (and I agree) that legitimate claims for commercial confidentiality need to be respected[21], which leads to a conflict with principles for transparency. In my view, the ultimate test for effective regulatory processes and practices is whether they are *credible with stakeholders by reflecting the principles of good regulation.* This definition of the objective encompasses both transparent publication of information, and credible / accepted arrangements for handling legitimate confidential information. These matters are discussed further below in section 3.4.2.

56. Secondly, my proposed framework highlights that the rules need to work together with merits review and judicial review, and with what I have called norms and behaviours. While this is implicit in the AEMC's original policy intent and comments by AEMC in the directions paper, I consider it important to acknowledge this interaction explicitly. This is discussed further below in section 3.4.4.

57. Thirdly, the framework highlights that other types of instruments such as guidelines, voluntary codes, or protocols may be more "fit for purpose" than are rules. Principles of best practice regulatory recognise that there can be a variety of different instruments other than rules that can be better suited to dealing with particular procedural questions.

58. Finally this framework highlights that monitoring of the performance of the regulatory processes plays an important role in their medium and long term development. This is discussed in section 3.4.5

3.4.2 Objectives for designing regulatory processes

59. The AEMC Directions Paper starts its discussion of objectives for the design of the regulatory processes by referring to this quote from the AEMC's 2005 Chapter 6A rule determination:

> *"... well designed procedural requirements assist in ensuring that the regulator administers the regulatory regime in an appropriate manner. This includes providing opportunities for regulated businesses and interested stakeholders to make submissions to the regulator and the opportunity for full and thorough analysis of the submissions and the regulator's decisions (including draft decisions). Transparent decision making in this way is conducive to reducing regulatory risk, and the probability of error and decreasing the administrative costs of regulation. Appropriate time constraints within this process also assist in ensuring that regulatory decision-making is timely and efficient"*

[21] I note that confidentiality can be required for reasons other than commercial confidentiality, such as infrastructure safety and security.

60. While I do not disagree with any individual aspects of this quote, I consider that it is not an adequate basis for discussion of the overarching objective for design of regulatory processes. First it contains a number of factors which are potentially in conflict. (For example full and thorough analysis of submissions can be in conflict with timely and efficient decision-making). Second there is no overarching objective which can help guide tradeoffs or suggest alternatives where there is tension between different factors. Third, it does not explicitly refer to some of the principles of good regulation (including proportionality, targeting). Finally it does not provide any guidance on dealing with legitimate commercial in confidence information.

61. Consistent with the discussion on the theory of economic regulation and principles of best practice regulation, I consider that the *overarching objective* for the regulatory processes and practices is more properly stated as:

> *The National Electricity Objective will be promoted through decisions that are credible to stakeholders by reflecting principles for good regulation*

62. Other benefits of this statement of the *overarching objective* include:

- It explicitly refers to the national electricity objective.
- It provides a clear way of dealing with confidential information (arrangements for dealing with legitimate confidential information must be credible for stakeholders).
- It enables consideration of all the principles of good regulation.

3.4.3 Design factors

63. The design factors should contribute to achieving the overarching objective. As noted in the figure above, I consider that the appropriate design factors for the regulatory processes and practices are as follows:

> *Regulatory processes and practices should be effective in enabling information to be developed, exchanged and assessed so as to:*
>
> - *provide opportunities for engagement by regulated businesses and interested stakeholders*
> - *reduce regulatory risk and probability of error*
> - *promote timely decisions*
> - *facilitate reasonable administrative costs*
> - *respect legitimate commercial confidentiality.*

64. These design factors are reflected in the NEL (See Annex 2 for detailed analysis) and are consistent with the AEMC's original statement in the Chapter 6A rule determination[22] except that it:

- provides a clear definition of what regulatory processes and practices involve, and
- recognises the need to respect legitimate commercial confidentiality.

65. In my view, it is helpful to define clearly what regulatory processes and practices involve. Essentially, they concern the exchange of information between the regulator, the regulated businesses, and interested stakeholders. The regulatory processes and practices deal with:

- how information is to be developed
- how and when information is to be published, exchanged, or kept confidential, and
- how and when the information is to be assessed by the AER.

66. I agree with the AEMC's view[23] that there will always be situations where there is information which legitimately is commercial in confidence. In my view, this situation should be formally recognised as a design factor, and should be considered in the same level of the hierarchy as 'reducing regulatory risk', 'timely decision making', and 'facilitating reasonable administrative costs'.

3.4.4 Norms and behaviours

67. I agree with the AEMC that the NER "cannot prescribe every detail of the process".[24] I consider it is important for the design of the regulatory processes and practice to recognise explicitly the role of what I have called "norms and behaviours." Norms and behaviours can be defined as "the rules that a group uses for appropriate and inappropriate values, beliefs, attitudes and behaviours which coordinate interactions with others". They work together with the NER, and merits and judicial review to help achieve the outcomes and objectives of the regulatory processes and practices.

68. What are "norms and behaviours and where do they come from? One source of norms and behaviours are the Codes of Conduct and Values established by the respective organisations. The AER and NSPs have (or should have) a statement of Values (or similar), and a Code of Conduct (or similar) which set out standards of behaviour and conduct expected of staff across the organisation.[25] A second source of

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[22] AEMC Final Rule Determination, p 33.

[23] AEMC Directions Paper, p 135.

[24] AEMC Directions Paper, p123.

[25] For example, AER staff are subject to the Australian Public Service Code of Conduct. The AER in its *Strategic Values and Priorities and work program* (2011-12) states that its values include: "transparency and cooperation; clarity, timeliness and

norms and behaviours is the culture of an organisation. Organisational culture is the shared norms and expectations that govern the way people in an organisation approach their work and interact with each other[26]. This is influenced by a number of factors in particular the behaviour of the organisation's leadership, as well training and development, remuneration policies and staff performance review. A third source is the specific norms and behaviours that develop amongst people involved directly in economic regulation. This includes such things as the openness (or otherwise) of information sharing; the willingness (or otherwise) to provide advanced notice of emerging issues; conduct of meetings, the style of verbal and written communication; and the ability (or otherwise) to work to resolve problems.

69. One of the challenges for developing effective norms and behaviours for the conduct of economic regulation is it's potentially adversarial nature. In my view the more active and successful are the parties in engaging in reasonable and cooperative behaviour within the rules, the less prescriptive the rules need to be. On the other hand, if parties engage in confrontational or opportunistic behaviour then this will lead to pressure for more prescriptive rules. I discuss in section 3.4.6 below my views on the appropriate approach for the AEMC to strike the right balance between rules, and informal norms and behaviours. Rules, with the potential for additional regulatory costs, with, arguably, less flexibility and poorer outcomes.

70. Although the AEMC can, as it has done implicitly in the Directions Paper, draw attention to the important role of norms and behaviours, the responsibility for setting, monitoring and influencing norms and behaviours largely rest with the leadership of the AER and NSPs as well as other stakeholder groups. I discuss in section 3.4.6 below my views on the appropriate approach for the AEMC to strike the right balance between rules, and desirable norms and behaviours.

3.4.5 Monitoring to support evidence based review

71. There will in future be further reviews of all aspects of the rules, including the design of the regulatory processes and practices. In my view, the efficacy of those reviews will be enhanced if they reflect *evidence-based policy*. It is useful for the AEMC to recognise explicitly the need for monitoring of the performance of regulatory processes and practices.

72. The AER publishes information to enable aspects of its performance to be assessed, for example a Stakeholder Survey. [27] It would be useful to supplement this qualitative information with performance

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consistency of regulatory approach; vigilance in market monitoring, compliance and enforcement roles; innovation to improve process and outcomes over time; and effective communication through high quality information."

[26] There are many different models for analysing and describing organisational culture. For example Cooke describes three general types of cultures: Constructive cultures; Passive/defensive cultures, and Aggressive/defensive cultures. *Cooke, R. A. (1987). The Organizational Culture Inventory. Plymouth, MI: Human Synergistics, Inc..*

[27] AER Stakeholder Survey Report, September 2011.

measures, and to collect and publish statistics on meaningful indicators of the performance of regulatory processes. Examples of statistics that could be published include:

- the number of cost pass through, contingent projects and capex reopener applications that are processed within the rule deadlines and how many exceed the deadline.
- the number of submissions made by a NSP in each regulatory determination
- the number and types of confidential information claims in each determination
- the number of statutory information requests made by the AER other than through the Regulatory Information Notice

73. This information can be used for a variety of purposes, including comparing the performance of different regulatory determinations; internal performance monitoring by the AER (including by the board); external monitoring of the AER by jurisdictions; and assessing the performance of comparable regulated businesses. Collection and publication of data can also encourage internal evaluation and self correction where there is poor performance.

3.4.6 Striking the balance between rules and norms and behaviours

74. There is a balance to be struck between rules and the norms and behaviours that affect the interaction between the AER and the NSPs. As noted above

- the original AEMC policy intent emphasised the importance of full and frank information flows and the need for effective communication between the AER and service providers
- the AEMC recognises the NER “cannot prescribe every detail of the process”
- the AER concerns (too many late submissions, and excessive or inappropriate use of confidentiality arrangements) suggest perceived or actual problems in achieving full and frank information flows and effective communication

75. I consider the AEMC should formally consider its general approach for striking the balance between reliance and rules, and relying on effective norms and behaviours.

76. I consider that the Chapter 6 arrangements are still in the process of maturing, noting that each NSP has only been through one regulatory determination (although there are a number of businesses and regulatory teams that manage multiple NSPs and gas network service providers). I consider it is too early to draw a conclusion that the balance struck in the original Chapter 6 Rules is not working effectively.

3.4.7 Administrative costs associated with the volume of material in a regulatory determination

77. The AEMC note that the volume and scope of material being assessed by the AER, and consulted upon with stakeholders, has increased over time which has resulted in increased administrative costs. The AEMC notes that one of the factors causing the increase in volume and scope of material is the merits appeal arrangements. The ENA suggested to me that another factor causing the increase in the volume of material is the scope of information required by the AER in its Regulatory Information Notice (RIN). It was suggested that the AER can require NSPs to provide large amounts of information that is not subsequently utilised by the AER or any other stakeholder. I consider that this is likely to be a valid concern.

78. I consider that it is not feasible to provide any further prescription in the rules to address this issue. The issue can only be addressed by the application of good regulatory practice – that is through applying principles for *Proportionality* and *Targeting*. It should be expected that as the regulatory process matures that the AER will review the scope of the RIN to ensure that only material that assists in informing its decisions is collected. Similarly as the merits appeal regime matures, the NSPs should be expected to be more selective in putting forward information.

79. As part of good regulatory practice it would be desirable for the AER and the NSPs to continue to engage in close dialogue so as to ensure the volume and scope of material required by the AER in the RIN or put forward by the NSPs is proportionate to the utility of the information in the regulatory process and recognises the administrative costs in collecting it.

4. Process elements of capital and operating expenditure factors

80. This section sets out my assessment of:

- The AER's rule change proposal that shifts so called "procedural"[28] matters from capex and opex factors, into the areas of Chapters 6 and 6A of the NER which deal with the procedure the AER is to follow in making regulatory determinations; and
- The AEMC proposal to remove the requirement on the AER to publish the analysis it has regard to in making its draft and final decision as previously specified within the third expenditure factor.

[28] Terminology adopted by AEMC Directions Paper, p 33. The AER used the term "process factors".

4.1 Shifting of first three expenditure factors to Part E of the Rules

4.1.1 Background

81. The so called "procedural" matters are the first three in the list of capex and opex factors and are[29]:

- the information included in or accompanying the building block proposal
- submissions received in the course of consulting on the building block proposal, and
- analysis undertaken by or for the AER and published before the distribution/transmission determination is made in its final form.

82. The AER proposes that the procedural matters which refer to sources of evidence be moved to Part E of the rules. Pursuant to Part E, the AER would still be required to:

- consider any written submissions
- consider the regulatory proposal or revised proposal, and
- have regard to analysis undertaken by or for the AER.

83. The AER explains as follows:

> *The first three expenditure factors list matters that are procedural in nature and do not substantively add to an assessment against the expenditure criteria. In practice, these expenditure factors create ambiguity as to whether specific weight must be given and how that is to be balanced with the other factors.*
>
> *Expenditure factor three requires that the AER only consider its own analysis if it is published prior to the making of the final decision. This has the potential to make decision making processes unworkable within the prescribed timeframes. It creates a cycle of publishing analysis that would then prompt a submission which in turn requires further analysis and so forth. This would create opportunities for gaming and delay.*

4.1.2 AEMC Initial Position

84. The AEMC agrees with the AER that

> *the "procedural" matters currently included as the first three expenditure factors appear to resemble more closely the procedural requirements found at other places in the NER and it would be appropriate to move these Part E of the rules as proposed by the AER.*

[29] The capex factors are set out in clauses 6.5.7(e) and 6A.6.7(e) and the opex factors in clauses 6.5.6(e) and 6A.6.6(e).

4.1.3 Assessment

85. The first question to consider is whether there would, or could be, a materially different outcome of the regulatory determination process if the AER Rule change proposal was implemented. That is, what is the effect if the rules were changed to require the AER "consider" the NSP regulatory proposal or revised proposal - as compared to current position where the AER is required to "have regard to" it?

86. This question is a matter of legal interpretation. The ENA sought legal advice[30] which is set out in Annex 3. In summary the legal advice is as follows:

> *We consider that the first three expenditure factors are not clearly strictly procedural in nature as the AER contends. Determining whether a clause is procedural or substantive to the regulator's decision making process requires a consideration of the Rule in its entirety, not the clauses in isolation. In light of the overarching requirement to "have regard" to the capex and opex factors, the first three expenditure factors are to be viewed as fundamental elements in the decision making process of the AER in deciding whether or not it is satisfied that the forecast opex or capex amounts reasonably reflect the expenditure criteria so to form a view as to whether it is required to accept or reject the proposals. This approach is made apparent in case law authority, which confirms that when a decision making authority is entrusted with a function to "have regard" to certain factors, those factors are not passive considerations, but mandatory elements to be factored into the relevant decision to be made.*
>
> *The phrase, "must have regard" has also been expressed to mean that the matters identified must be the focal point of the decision-making process.*
>
> *The requirement to "have regard" to the first three expenditure factors transforms their otherwise procedural content to form part of the substantive matters relevant to the AER's decision making in respect of determining whether or not it is satisfied that the proposed forecast reasonably reflects the required expenditure. Therefore, the current Rules operate to require the AER to take the specified information, submissions and analysis into account and to "give them weight as fundamental elements" in assessing the forecast expenditure with a view to reaching that particular decision. The expenditure factors listed are evidentiary matters which constrain and guide the judgment of the AER in accepting or rejecting the capex and opex forecasts.*
>
> *Consistent with the analysis provided above in Re Dr Ken Michael, it is appropriate to refer to the broader decision making purpose affected in determining the significance of proposed amendments. The importance of the capex and opex forecasts is in the determination of the overall regulated revenue amounts. In light of the requirement on the AER to accept those amounts where it is satisfied on the material before it that the forecasts are consistent with the requirements of the Rules, it is clearly appropriate that the AER be required to give the material before it on those forecast amounts weight as fundamental elements in making its decision. Contrary to the AER's contentions referred to above, the current process required by the Rules delivers certainty as to the matters to which the AER must have regard in making its determination that is a consideration of each of the matters equally.*

[30] Memorandum of advice from Gilbert & Tobin to ENA, 15 April 2012: *AER proposed Rule change: Assessment of the AER's proposed changes to the capital and operating expenditure factors.*

> *Under the current Rules, the AER is not directed as to what material it should give primacy. It is clear that the AER can only substitute a forecast capex or opex value where it has formed a view that the NSP's forecast is not consistent with the Rule requirements. However, this is not equivalent to a requirement that the AER give the NSPs proposal primacy in assessing the forecast amounts. Under the AER's proposal, the AER would be required to take into account or have regard to, the analysis undertaken by or on behalf of the AER, and consider the information in the NSPs proposals and written submissions. In light of general statutory interpretation principles it would be imprudent to underestimate the change in expression from "have regard" to" to "consider". Those principles indicate that all words or phrases must prima facie be given some meaning and effect, and that conclusion is even more compelling if the phrase in question has been altered by amendment.*
>
> *It follows then, that a possible legal interpretation of the AER's proposed rule change is that the AER would be required to give primacy to its analysis. This is a material shift from the current position in which the information in the NSPs proposal, the material in submissions by stakeholders and the AER's analysis are to be treated equally. It is also contrary to the position of the Australian Competition Tribunal (the Tribunal) which affirmed that it is the material before the AER, and in particular the material submitted by the service provider, that will fundamentally determine whether the AER can be satisfied as to the service provider's capex and opex forecasts.*

87. Based on this legal advice I conclude that the AER rule change proposal could result in a significant change in the standards that apply to the AER for the analysis and justifications that need to be provided in AER's determinations. This does not appear to be the AEMC's intention in its initial position to agree to the AER Rule change proposal.

88. The second question is as follows. Given that the AER's proposal may result in a significant change in the analysis and justifications that need to be provided in the AERs decisions, is this consistent with the AEMC original policy intent?

89. My review of the extrinsic material suggests that it was clearly intended by the AEMC that these three factors should be "fundamental elements" in the decision making process of the AER. It is clear that the original policy intent was to seek transparency and certainty in the AER's decision making and to reduce the risk of regulatory error. The following statements of the AEMC and policy makers summarises the original policy intention related to the procedural elements of the capital and operating factors, with key aspects highlighted:

> *The procedural elements of the capital and operating factors should...*
>
> - *provide the AER with sufficient discretion as to the **approval/rejection of the forecast operating expenditure** if it determines that the estimates are reasonable, which is assessed according to specified factors/principles/objectives provided in the legislation.*[31]
> - *ensure that service providers obtain independent certification of its capital and operating expenditure forecasts.*[32]

[31] AEMC Draft Rule Determination, pp 49-50; see also pp 25-26; AEMC Final Rule Determination, pp xv, 35, 43-53.

> - *not weigh elements of the assessing criteria as that would limit flexibility in considering the* ***unique circumstances of the distribution business***[33] *during a regulatory determination process.*[34]
> - ***oblige the AER to provide reasons*** *when a submission from a DNSP is not reasonable*
> - *provide for an appropriate level of discretion in that* **the AER should have to accept a forecast where the DNSP can demonstrate that it is reasonable and properly allocated in accordance with designated principles and policies** [35]

90. The third question in my view is, whether the original policy intent remains appropriate? I consider that the original policy intent continues to be appropriate for the following reasons:

- The AER provides no evidence of practical problems with the current rules. The AER rationale for the proposal – that there is ambiguity as to whether specific weight must be given and how that is to be balanced with the other factors – is not justified by the AER. It appears to be a theoretical concern.
- Principles of good regulation for transparency and accountability for AER decision making continue to be valid. Requiring that the AER to treat the NSPs forecast as "fundamental elements" that it should have regard to and requiring that the AER to provide its reasoning where it does not accept the NSPs forecasts, would continue to promote important principles of transparency and accountability.
- There is no evidence that the current rules provisions constrain the AER in any way from rejecting the NSPs forecasts where the AER considers they are not reasonable and is able to demonstrate its reasoning.

91. In addition it is relevant that a Australian Competition Tribunal decision has affirmed that it is the material before the AER, and in particular the material submitted by the service provider, that will fundamentally determine whether the AER can be satisfied as to the service provider's capex and opex forecasts[36].

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[32] AEMC Draft Rule Determination, pp 49-50. The requirement for certification in the rules, which are quite onerous on the business, provides support to the view that the NSP forecasts were viewed as a fundamental elements in the decision making process.

[33] The NSPs own forecasts are clearly a fundamental input into understanding the "unique circumstances of the distribution business".

[34] Ministerial Council on Energy, 'SCO responses to stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution revenue and pricing (Chapter 6)', Table 1 accompanying Energy Market Reform Working Group Bulletin No. 105: Second Exposure Draft of Distribution National Electricity Rules Amendments, October 2007 (SCO table of responses to stakeholders), pp 25-29; AEMC Final Rule Determination, pp 33-35.

[35] SCO table of responses to stakeholders, pp 25-29; AEMC Final Rule Determination, pp 33-35.

[36] See discussion of Application by Ergon Energy Corporation Limited [201] in Gilbert and Tobin advice to ENA, 13 April 2012.

92. Therefore I conclude that the rules should not be changed. The first three expenditure factors should be retained within the current list of capital and operating expenditure factors that the AER should be required to have regard to.

4.2 Consultation on material relied on by the AER in the final determination

93. I noted above (see Section 3.3.3) that subsection 16(1) of the NEL requires that where the AER in exercising a function or power performed relating to a distribution determination or transmission determination, that it must ensure that the regulated NSP (and others) are:

> *given a reasonable opportunity to make submissions in respect of that determination before it is made.*

94. It is a matter of legal interpretation as to whether the AEMC initial position - that the AER would not be obliged to publish and consulting on analysis before the draft or final regulatory determination stage - is consistent with subsection 16(1) of the NEL. Similarly, it is also a matter of legal interpretation as to whether the AEMC's consideration that scrutiny of material that had not been published by the AER prior to a final determination could properly be through merits review. Legal advice[37] provided to the ENA (see Annex 3) states that:

> *Section 16(1) is expressed in mandatory, not permissive terms, as construed by the words "must" and "ensure". It follows then, that the AER must make available to the NSP, and where relevant, other stakeholders, all analysis that is material to the making of its final decision prior to that final decision being made in order that the NSP can respond to that material. In making a final determination, if the AER has had regard to analysis that it has not made available to the relevant NSP, and therefore not brought to the attention of NSPs and stakeholders, such conduct would be contrary to section 16(1) of the NEL.*
>
> *The AEMC in its Directions Paper which responds to the AER's Rule change proposal considered that that:*
>
> - *the Rules could be clarified to make it clear that there is an obligation on the AER to publish its analysis with its draft or final regulatory determinations, but no obligation to do so prior to this; and*
> - *scrutiny of material relied on in the final regulatory determination by the AER which was not relied on for the draft determination (and not published by the AER, or the subject of submissions) would be through merits review.*
>
> *However, those proposals could be considered to be contrary to a number of provisions in the NEL.*
>
> *First, the requirement in section 16(1) that the AER is required to inform the relevant NSP and other parties of matters that are material to the AER's decision and be provided with an opportunity to respond to those issues, must logically occur before a final decision is made.*

[37] Memorandum of Advice from Gilbert + Tobin to the Energy Networks Association, 15 April 2012 (footnotes from original memo omitted).

> *Second, the evidentiary limitations in the NEL that apply to merits review. Specifically, that the Tribunal may only have regard to "review related matter" in determining whether a ground for review in a merits review application has been made out (section 71R(6)).. In broad terms this term "review related matter" has been interpreted to be the material that was before the AER when it made its final determination and, in certain circumstances, material referred to in materials that have been provided to the AER. If the AER was not required to make available material until the publication of its final decision, material responsive to the AER's material would not have been submitted by the NSP or any other relevant stakeholder, and therefore it would be difficult to have any meaningful merits review of the matter. These evidentiary limitations mean that scrutiny of material relied on by the AER and not published, or otherwise made available to the NSP and other relevant stakeholders cannot be through the merits review process.*

95. Therefore based on this legal advice I consider that AEMC's initial position is not well founded given the inconsistencies that arise between that position and the NEL.

5. NSP submissions received during a regulatory determination

96. The AER proposes rule changes to limit NSP rights to make submissions during the regulatory determination process. This section sets out my opinion on the AEMC's analysis and initial views. I note that while the section in the AEMC Directions Paper is entitled "*NSP submissions received during a regulatory determination*" - reflecting the AER's rule proposal – the section actually is far broader and deals with how "new information" is dealt with through the entire regulatory determination process. The section deals with the following broad questions:

- What factors or principles would promote an effective regulatory determination process? (Question 35)
- Which option(s) would be the best way of addressing problems with the regulatory determination process? (Question 36)

5.1 Background

97. Currently, the rules provide that the AER must have regard to submissions made in response to the draft decision and on a revised proposal, and may, but is not required to, have regard to submissions made pursuant to an invitation for submissions after the time for the making of submissions has expired.[38] The proposed rules changes reflect the AER's concerns that the NSPs are undermining the effective operation of the regulatory process by providing material that should be part of an initial or revised regulatory

[38] NER, cll 6.10.1, 6.11.1, 6.14 and 6A.12.1, 6A.13.1, 6A.16.

process later in the process in the form of submissions. Specifically, the AER considers there are three problems created by NSPs making substantial submissions after lodging a revised regulatory proposal on matters which should have been covered in their proposal and/or revised proposal:

- it may undermine incentives for NSPs to provide complete proposals
- other stakeholders are unable to consider and make meaningful submissions on material submitted by the NSP after the revised proposal, and
- the AER may have insufficient time to properly consider this material.

98. The AER proposes that:

- NSPs would be unable to make submissions on their own initial and revised regulatory proposals, and the AER's draft decision.
- NSPs would only be able to respond to the AER's draft decision in the form of their revised regulatory proposals.
- NSPs would also be able to make submissions on the AER's proposed negotiated service criteria released concurrently with the NSPs' initial regulatory proposals, and submissions from other stakeholders into the regulatory determination process; and
- the AER would not be permitted to consider late initial or revised regulatory proposals or submissions that do not comply with the above restrictions.

99. The AER's proposed rules would remove the ability of a NSP to make submissions on their own initial proposal, the AER's draft decision, or their own revised proposal. Accordingly, the mechanism by which NSPs respond to the draft decision would be through their revised proposal (and not through submissions or through a combination of their revised proposal and submissions).

100. The proposed rules would also <u>require</u> the AER to *not* consider new information in a NSP's revised proposal which goes beyond responding to the draft decision, and provide for the AER to *not* consider submissions which do not comply with the restrictions on late proposals.

101. The proposed rules would not restrict an NSP's ability to make submissions on:

- other NSPs' proposals for determination processes that run concurrent to the NSP's own determination process, where those proposals are materially different to the NSP's own proposal, or
- the AER's proposed negotiated service criteria which are released at the same time as the NSP's initial proposal.

5.2 Is there a problem?

102. I agree that there is a problem here that needs to be addressed. The AER faces a tension between objectives. On the one hand, it has an objective of making the best possible regulatory determination (in effect promoting the national electricity objective) which requires taking into account all valid information. On the other hand it has an objective of ensuing the regulatory process is efficient and timely (which requires that information is provided so that the AER has enough time to analyse it) and is transparent (it can be subject to maximum opportunities for scrutiny by stakeholders).

103. While the AER has discretion as to whether to have regard to submissions made after the time for making submissions has expires which, in principle, enables it to set its principles and criteria for managing this tension, I consider this is a matter that is properly the subject of clarification.

5.2.1 AEMC proposed principles

104. This section discusses the principles proposed by the AEMC Directions Paper (section 7.2.6).

5.2.1.1 The AER should have enough time

105. The AEMC's initial position is:

> *The AER should have enough time to scrutinise material provided by a NSP in its initial and revised regulatory proposals, including a clear period of time to consider all relevant and significant material submitted during a regulatory determination process prior to making its final regulatory determination*.

106. I agree with the AEMC's initial position in relation to the final determination - it is clear that the AER requires "sufficient time" to consider all relevant and significant material submitted during a regulatory determination prior to making its final determination. I also agree with the AEMC initial position in relation to the AER making its draft regulatory determination on the initial regulatory proposal.

107. However the AEMC's initial position begs the question as to what is "a reasonable period of time", and who is in the best position to decide this. It is self evident that only the AER can determine what is a reasonable period of time, in any given circumstances.

5.2.1.2 Reasonable opportunity for NSPs, other stakeholders to scrutinise and comment on material submitted by others

108. AEMC's proposed position is:

> *The regulatory determination process should provide a reasonable opportunity for a NSP and other stakeholders to comment on and scrutinise material submitted by each party during the regulatory determination process that is on an equal footing.*

109. My starting position in addressing this objective is to restate my view (discussed above) that the overarching objective for the regulatory process and practices is that they are credible for all stakeholders.

Providing opportunities for stakeholders to scrutinise and comment on material submitted by each party is an important means to achieve this objective, but should not be an objective in itself.

110. In my experience, there are many matters contained in an NSP's regulatory proposal that are of interest to other stakeholders and therefore, in relation to these matters, I agree that it should be an objective that those stakeholders should, as far as possible, have an opportunity to scrutinise this information.

111. However there are also types of information that are of no interest to any other stakeholder because:

- they have no specific insights or knowledge about this information
- it is not material, or
- it does not affect their interests.

Stakeholders are content to leave it to the AER and its advisers to scrutinise this information.

112. There may be merit in allowing the AER the flexibility to consult with stakeholders to develop guidelines identifying any areas in which stakeholders are not interested, or in which stakeholders lack the capability to scrutinise and comment on materials.

5.2.1.3 NSPs should have sufficient time to prepare revised regulatory proposals

113. The AEMC's initial position is:

> *NSPs should have sufficient time to prepare their revised regulatory proposals and should submit as much relevant information as possible in their revised regulatory proposal.*

114. It is self evident that NSPs should have sufficient time to prepare their revised regulatory proposals. I agree with the principle that NSPs should submit as much relevant information as possible in their revised regulatory proposal. If the revised proposal is not substantially complete then the AER will have difficulty in managing the work required to scrutinise the revised proposal and makes its final determination.

115. I note that this wording implies that there may be exceptions to this principle. I consider that if the AER is able to manage supplementary information that needs to be provided by the NSP, for good reason, after the deadline for submission of the revised regulatory, then the rules should provide flexibility for this to occur.

5.2.1.4 Restrictions on content of the revised regulatory proposal

116. The AEMC's proposed position is:

> *In circumstances where a restriction is imposed on the content of the revised regulatory proposal, the NER should not permit this restriction to be circumvented through the use of submissions.*

117. I understand that the AEMC is suggesting introducing some type of restriction in the rules on matters that cannot be the subject of submissions. I consider this is not necessary or appropriate, since it introduces an absolute prohibition on the AER having regard to what, may be useful information. This may tend to increase the risk of regulatory error, and therefore does not promote the national electricity objective. I understand that the intent of introducing such a restriction is to increase the incentives for NSPs to provide complete initial and revised proposals. Since the AER already has discretion to disregard submissions that are made outside of the time for making submissions, this, in my view, is a more appropriate and flexible way of creating such an incentive.

5.2.1.5 Regulatory determination process should encourage dialogue

118. AEMC proposed position

> *The regulatory determination process should encourage dialogue between the AER and NSPs to establish a common understanding of the issues*

119. I support this principle. Indeed, I consider that this should be a key starting point for dealing practically with the problem. As noted above, the AEMC's policy intent included enabling full and frank information flows, and promoting effective communication between the AER and service providers.

120. In my view, at the outset of a regulatory process, the AER should make it clear to the NSP's (and other interested stakeholders) the AER's internal timelines; the extent (if any) to which the AER has the resources to deal with late submissions; and any particular issues on which the AER seeks stakeholder comments. Likewise, the NSP should signal any possible areas of uncertainty, and the potential for submissions (if permitted). The AER and NSP should work together to plan for and anticipate potential issues and problems, and then maintain an ongoing dialogue.

121. In my experience, this type of dialogue does occur, though its efficacy is variable. This is due in part to the approach adopted by the respective organisations, and the capability and experience of the people involved. Ultimately, the regulatory processes and practices embedded in the rules are a necessary, but not sufficient, condition for effective dialogue and planning to occur.

5.3 AEMC options for dealing with submissions during a regulatory determination

5.3.1 Option 1

122. Option 1 is to create new consultation steps in the regulatory determination process. One option is to require a mandatory issues paper on the regulatory proposal. Another is to introduce a process of submissions and cross-submissions on the draft decision and revised regulatory proposal.

5.3.1.1 Issues paper on regulatory proposal

123. The Victorian Department of Primary Industries proposes a mandatory issues paper be published by the AER following receipt of the NSP regulatory proposal. Its purpose would to be to facilitate better consultation with stakeholders, given the large volume of information submitted by the NSPs.

124. I am supportive of this proposal, subject to an assessment of the administrative cost implications. In my experience, the AER staff form a view of likely key issues quite early in the review of the NSP initial proposal. These preliminary views inform planning for the AER's review work, including as inputs to the terms of reference for consultants' reviews, and for communication with senior management and the AER board. Therefore, an issues paper should make public work already undertaken, and not entail significant additional work for the AER. If an issues paper step were introduced, then its content should *not* be binding on the AER, nor constrain its subsequent decisions.

125. I consider that this step would facilitate better and more efficient stakeholder engagement, given the large volumes of material contained in the NSP's regulatory proposal, and the work already undertaken within the AER. The issues paper could assist the AER by signalling key issues on which it seeks stakeholder views. This would encourage more targeted and effective allocation of any resources committed by stakeholders in scrutinising the regulatory proposal and providing submissions.

5.3.1.2 Submission and cross submissions

126. The ENA has proposed, as an alternative means of promoting greater stakeholder involvement, introducing a process of submissions and cross-submissions on the draft decision and revised regulatory proposal. This would allow stakeholders to consider and comment on any further submissions made by the NSP, and would allow the NSP to respond to any submissions made by third parties on its revised proposal. They note that this model is used as a matter of practice by the New Zealand Commerce Commission. The ENA states that introducing cross-submissions would not alleviate the need for AER discretion in treatment of late submissions. There may still be circumstances in which further submissions are necessary, and the AER should maintain discretion to deal with such late submissions on a case-by-case basis. The ENA proposes that a further three weeks be allowed after submissions on the revised proposal for cross-submissions. The ENA state that this would be a relatively minor adjustment to the decision-making timetable and would greatly improve opportunities for stakeholder participation.

127. Currently, the deadline for submissions on a draft regulatory determination means that all submissions arrive at the same time. In practice, this means that there is no opportunity for testing of the submissions made by different parties by those with an alternative view. Introducing cross submissions would shift some of the emphasis in the regulatory process away from the AER acting essentially as the sole arbiter of the varying points of view on the revised regulatory proposal, and towards an environment where there

is wider debate between NSPs and stakeholders. I consider that this would improve the credibility of the regulatory process with stakeholders.

128. My understanding[39] is that this process generally works quite well in New Zealand, although it raises a number of issues:

- Submitters may still seek extensions to the initial submission timeframe. This then requires a decision on whether to extend the date for cross submissions as well, or only in respect of the late submissions.
- Submitters may lodge material late, regardless of the specified timeframes.
- Submitters may lodge material on time, but outside the scope of the consultation process.
- Cross submissions may raise entirely new matters that were not raised in the original submissions.

129. I consider that the AEMC should explore a submission / cross submission process, but suggest the process requires careful design to take into account the above issues. For example cross submissions should be limited to matters raised in submissions and not raise new matters.

5.3.2 Option 2

130. Option 2 is to extend the period for NSPs to submit revised regulatory proposals. The AEMC suggests that, given the difficulty some NSPs experience in preparing revised regulatory proposals over the Christmas and New Year period, the current 30 business day period could be extended by an additional two weeks where it falls in this period. This option seems sensible, but should be considered within the totality of any changes to the regulatory process timelines.

5.3.3 Option 3

131. Option 3 is to commence the regulatory determination process earlier, thereby extending the duration of the regulatory determination process. This option also seems sensible, but again, needs to be considered within the totality of any changes to the regulatory process timelines.

5.3.4 Option 4

132. Option 4 is to delay the publication of the final regulatory determination until a specified number of days after the last material submission is received.

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[39] Personal communication.

133. I consider that, occasionally, delaying publication of the final regulatory determination may be necessary and that the rules should provide for this. An example is where a major external event occurs late in the regulatory process. I consider a rule that delays the final regulatory determination by a fixed time period is too prescriptive. Provided the AER is not bound to have regard to a material submission (which I recommend), then I consider that it is appropriate to leave it to negotiation and agreement between the AER and the NSP as to the need for, and the period of, any delay in publishing the final regulatory determination. The NSP is in an appropriate position to make tradeoffs as to the benefits (in terms of the AER being able to consider a submission) and any costs (e.g. pressures in finalising network prices) of a delay. The AER is also in an appropriate position to evaluate the benefits of reviewing a submission against other relevant factors (such as costs, and resources).

5.3.4.1 Option 5

134. Option 5 is to restrict the scope of NSP submissions as proposed by the AER.

135. I disagree with the AER proposal.

136. Firstly, there are valid reasons why submissions may be required in response to some external event and new information outside of the control of the NSP. It is reasonable to expect that a NSP provides a full and complete initial or revised regulatory proposal based on the situation at (or shortly before) the due date for lodgement. But new events or information can and do arise close to, or after, the NSP lodges it's initial or revised regulatory proposal such that it is not practical for the NSP to analyse the event and information. As noted by the AEMC, the AER's proposal could result in relevant new information - that is not reasonably able to be predicted or managed by the NSP - not being considered, thereby increasing the risk of regulatory error.

137. Secondly there are minor pieces of information or clarification, which in practice can be taken into account by the AER without compromising other stakeholders' rights. In my view the AER should be able to use its discretion as to whether to accept this information, as this may also help the risk of regulatory error.

138. Thirdly, as noted above, the AER already has discretion to disregard submissions, and the AER can use this discretion to create incentives on the NSP to provide a substantially complete submission.

139. However in my opinion, the current processes for dealing with submissions create conflict and uncertainty. Therefore the regulatory regime (either the rules, or the way the AER applies the rules) should be amended. I consider the best approach to reducing conflict and uncertainty in relation to submissions is by way of changes to the way the AER applies the rules. Specifically I suggest the AER should consult on, and issue a guideline clarifying how it will exercise its existing rules discretion on how it expects to have regard to submissions.

140. First, the guideline should set out principles to be applied to define appropriate matters or reasons why NSPs may need to provide a submission. These principles could include:

- That the AER expects a NSP should provide a full and complete initial and revised regulatory proposal based on the situation at or shortly before, the due date for lodgement.
- That flexibility is required by the AER as to how it may have regard to information related to events that are outside of the NSP's control including:
  - external events (such as the Victorian Bushfire Royal Commission recommendations); or alternative approaches or evidence raised by stakeholders.
  - the guideline could create a new category of submission that perhaps could be called "external event submission"
  - the AER should in my view undertake to have regard to such submission "as far as practicable". That is, the AER would undertake to take account of such submission to the extent it is practical to do so, including where the NSP agrees to a delay in the date for publication of the final determination.
  - But the Guideline could indicate that the AER need not have regard to the submission, if it is received too late, or if the AER has inadequate resources, or a delay in the date for publication of the final determination is not agreed.
- That the AER may, but need not, have regard to information or clarification that the AER consider is non controversial, or is minor and can be taken into account by the AER without compromising other stakeholder interests.

141. Having clarified these principles the AER would then be on stronger grounds to decline to have regard to a submission that falls outside these principles.

142. The guidelines could include an expectation on processes for dealing with new information and submissions:

- The AER and NSP staff should be in close dialogue as to how to deal with specific potential new information and submission issues related to a specific NSP. In this context, the AER staff should set specific expectations as to how they intend to exercise the AER discretion on submissions. By doing so, they can create clearer incentives on the NSPs on how to provide substantially complete initial and revised regulatory proposals.
- The NSPs should be expected to advise the AER as soon as practicable once it is aware that there is an issue that may give rise to a submission. This would promote the necessary dialogue to plan for how to address the issue.

143. An alternative to the AER clarifying how it will exercise its discretion through a Guideline, would be for the AEMC to make changes to the rules that reflect the principles discussed above. While this approach would be feasible, I consider it is not the preferred approach. The AER in consultation with stakeholders are in the best position to develop a Guideline that is fit for purpose.

5.4 Summary of proposed measures to address problems with the regulatory determination process

144. I consider the measures to address problems associated with new information and submissions by NSPs should be considered as a package. The following summarises my views outlined above.

Proposal	Rationale
The AER should consult on, and issue guidelines clarifying how it will exercise its existing rules discretion on how it may have regard to NSP Submissions. The Guideline would set out • Principles for how the AER would define appropriate matters for when the NSPs may need to provide a submission. • Processes, including: – an expectations that AER and NSP staff should be in close dialogue as to how to deal with specific potential new information and submission issues related to a specific NSP – an expectation that NSPs advise the AER as soon as they are aware of a new issue that may give rise to a submission.	Improved certainty as to how to manage new information.
The regulatory determination process should encourage dialogue between the AER and NSPs to establish a common understanding of the issues AER staff should set clear expectations as to how they intend to exercise discretion on submissions, to create clear incentives on the NSPs to provide substantially complete initial and revised proposals.	Regulatory efficiency and timeliness
It should be mandatory for the AER to publish an issues paper following receipt of the NSP initial proposal. The issues paper content should not be binding on the AER, nor constrain its subsequent decisions.	Improved credibility for the regulatory process, increased efficiency: • Facilitate better consultation with stakeholders given the large volume of information submitted by the NSPs. • This recommendation is subject to assessing the administrative cost implications (not expected to be

Proposal	Rationale
	significant). It may result in lower overall social costs since stakeholders avoid some costs in reviewing the NSP submission to indentify issues.
The AEMC should introduce a process of submissions and cross-submissions on the draft decision and revised regulatory proposal.	Improved credibility for the regulatory process • Allows stakeholders to consider and comment on any further submissions made by the NSP and would allow the NSP to respond to any submissions made by third parties on its revised proposal. • Shift the emphasis in the regulatory process away from the AER acting as the sole arbiter of the varying points of view on the draft decision and the revised regulatory proposal
Consider options for extending the regulatory period including: • Option to extend the current 30 business day period by an additional two weeks where it falls in this period. • Commence the regulatory determination process earlier	Reduce probability of regulatory error • Increased time flexibility for managing regulatory workload
Provide for delay in publication of the final regulatory determination after the last material submission is received, where this is due to an “external event” and by agreement between the AER and NSP.	Reduce probability of regulatory error • Flexibility for addressing material new information
Consider requiring the AER to consult with stakeholders and perhaps developing guidelines to identify areas of detail where stakeholders do not have an interest or capability in commenting and scrutinising material.	Improved regulatory efficiency • Transparency as to what issues should be subject to consultation and which need not • Increased regulatory efficiency, by ensuing interested stakeholders are provide with better targeted information and opportunism to engage with the regulatory process

6. NSPs’ proposals claiming confidentiality

145. This section sets out my views on the AER’s proposed rule amendments related to NSP claims for confidentiality, and the AEMC’s initial position. It sets out my response to the questions raised by the AEMC.

6.1 Background

146. The NER provides that, where submissions that have been identified as confidential, the AER may give such weight to confidential information as it considers appropriate. There is no equivalent provision in the NER with respect to confidential information in an NSP's initial and revised regulatory proposal.

147. The problem the AER identifies is that, where confidentiality is claimed in an initial or revised regulatory proposal, this denies other stakeholders the opportunity to scrutinise, comment or respond to the relevant information. The AER proposes amendments to the NER which would:

- require NSPs to identify parts of the initial or revised regulatory proposal given to the AER that are claimed to be confidential, and
- provide the AER with the discretion to give such weight as it considers appropriate to confidential information in an initial or revised regulatory proposal. This discretion would be equivalent to the current discretion given to the AER in weighting confidential information in submissions.

6.2 AEMC initial position

148. I agree in principle with the AEMC's initial position on the proposed rule change and rationale:

> *The NER should provide scope for as much testing and scrutiny of initial revised regulatory proposal as possible while upholding legitimate claims of confidentiality.*
>
> *There will almost always be information included as part of a NSP's initial or revised proposal which is legitimately claimed to be commercially sensitive and confidential.*
>
> *It is important that the probative value of as much of a NSP's initial or revised regulatory proposal as possible is able to be tested with stakeholders.*

6.3 Clarifying AER proposal

149. An issue to be clarified for the AER Rule change proposal is whether discussion between the AER and NSPs could resolve the concerns, at least in part. Under the NEL, the AER is authorised to disclose information given to it in confidence, where the person from whom the person received that information, has given written consent to the AER to disclose that information. In the AER's discussion of the proposed rule change[40] it is not clear whether the AER has, in the first instance, approached NSPs that have 'indicated' commercial in confidence information in their regulatory proposal to discuss whether they are prepared to provide consent to the information being released either in full or in a modified way. I note that the proposed rule change appears to assume that such discussions might not be a reasonable solution, at in least to part, to the problem raised by the AER.

[40] AER Rule change proposal, *Economic regulation of transmission and distribution network service providers, AER's proposed changes to the National Electricity Rules*, September 2011, p 90 (AER Rule change proposal).

6.4 Questions raised by the AEMC

150. This section addresses the three questions asked by the AEMC.

- Should the AER be given more time to consider confidentiality claims in initial and revised regulatory proposals? (Question 39)
- Should the NER be clarified to reflect the NEL and/or common law position with respect to the AER's ability to give weight to confidentiality claims in initial and revised regulatory proposals? (Question 39)
- Alternatively, are there any other additional ways to address confidentiality claims in initial and revised regulatory proposals that are not currently available under the NER? (Question 40)

6.4.1 Framework for addressing questions on how to improve management of confidential analysis

151. This section sets out my views on the appropriate framework for addressing these questions.

152. In my view, it is important to identify the right underlying issues and objectives for changes to confidentiality arrangements, before being able to properly assess the options.

153. The most important question in my view is, "How to facilitate an environment where the quality and relevance of probative submissions provided by stakeholders is maximised". While it is also important that stakeholders' have general confidence in an open and transparent regulatory process, in my view it is important that this design feature does not limit the ability for stakeholders to provide probative submissions that are of assistance to the AER.

154. In reality, I have observed that probative information from third parties - information that can add value to the AER's scrutiny of NSP initial and revised regulatory proposals - will come from analysts and experts representing stakeholder groups. This reality reflects the volume and complexity of the information that must be assessed. Very little probative information comes from the stakeholder community at large. Indeed, I think that it is widely agreed that one of the areas that would improve the credibility of the regulatory regime would be to improve the resourcing of, and hence quality of, expert stakeholder analysis.

155. Therefore the overarching objectives for any changes to confidential information arrangements, in my opinion, are:

- to promote the most efficient and effective environment to allow analysts and experts representing the stakeholder interest to have access to all relevant confidential information, and
- through this measure, to enhance the confidence of the broader stakeholder community.

156. Having clearly identified the right question, I consider it is possible to use accepted regulatory cost benefit analysis to evaluate and compare the net public benefit of the various options. I have not undertaken a full regulatory analysis of the options, but I recommend that the AEMC does so. In the next section I identify and describe each of the options. Then I set out high level comments on what I consider a proper regulatory cost benefit analysis may find. I then identify the option that appears most promising for the AEMC to evaluate further.

6.4.2 Options for improving the management of confidential information

157. The options for improving the management of confidential information are as follows.

Options for improving the management of confidential information	Notes
Option 1. Provide the AER with more time to consider confidentiality claims in initial and revised regulatory proposals	AEMC Question 38
Option 2 Clarify NER to reflect the NEL and/or common law position	AEMC Question 39
Option 3. Codification to better define scope of legitimate confidential information	An option I have identified. Potentially a way to address confidentiality claims in initial and revised regulatory proposals (AEMC Question 40). Could be introduced voluntarily by NSPs or be provided for in rules
Option 4. System for limited disclosure to third parties	Suggested by ENA Potentially a way to address confidentiality claims in initial and revised regulatory proposals (AEMC Question 40) Could be introduced voluntarily by NSPs or be provided for in rules.

6.4.3 Description of options

158. I set out below a brief description of each option.

6.4.3.1 Provide the AER with more time to consider confidentiality claims

159. The AEMC states that the AER appears to have existing powers under the NEL and common law to use discretion in determining the weight to be given confidential information in initial and revised regulatory proposals. The AER indicates that the current timeframes make it infeasible to apply the public interest tests under section 28ZB of the NEL. The AER indicates that its internal processes are being improved upon to allow it sufficient time to make use of this discretionary power. The AEMC consider these powers may represent a possible solution to the issues raised by the AER, and if the issue is primarily that the

AER has insufficient time to apply the existing powers, then it may be appropriate to consider an extension to the time period to allow the AER sufficient time to assess claims of confidentiality.

6.4.3.2 Clarify NER to reflect the NEL and/or common law position

160. This option would seek to clarify the NER to reflect the NEL and/or common law position with respect to the AER's ability to give weight to confidentiality claims in initial and revised regulatory proposals.

6.4.3.3 Codification to better define scope of legitimate confidential information

161. At present claims for confidential information are made by NSPs and considered by the AER on a case by basis. I understand that there is a considerable degree of commonality in the confidentiality issues that arise across regulatory determinations. At the same time, there are also some more unusual and unique issues that may arise. For example, some NSPs have business models that involve different types of outsourcing arrangements.

162. This suggests an option of codifying the principles and definitions for legitimate confidential information. Codification would involve: developing principles for defining legitimate commercial in confidence information; and applying these principles in order to identify common categories and definitions of legitimate confidential information.

163. The potential benefits of codification could include a more rigorous and credible process for identifying principles than exists currently; improved consistency; simpler decision making processes and lower costs for businesses; and reduced AER regulatory costs.

164. There are different options for how codification could be achieved and the status of any code. These include an AER Guideline; a voluntary industry code; or a non binding protocol reflecting agreement between the NSPs and the AER.

165. I consider the best option for codification of confidentiality arrangements would be an AER Guideline. The Guideline would be developed by the AER in consultation with NSPs and stakeholders and set out general principles, and definitions for common categories of legitimate confidential information. The code would not be legally binding on the AER or NSPs.

166. A Guideline is preferred because an AER led process for developing the guideline would foster improved understanding and credibility for the arrangements; and is likely to create more certainty and lower regulatory costs then other options.

6.4.3.4 System for limited disclosure to third parties

167. As set out by Gilbert and Tobin in its advice to the ENA[41], there is an option to develop a system for limited disclosure to third parties involving third party nondisclosure agreements. Such limited disclosure regimes are commonly used by regulators in other industries, including the ACCC. For example, in telecommunications, the ACCC typically negotiates with carriers for limited release of confidential information to third parties, subject to those third parties executing appropriate confidentiality undertakings.

168. In practice, I envisage this would involve consumer group representatives and experts entering into nondisclosure agreements with the relevant NSP. The system would then enable confidential information to be freely shared between these persons, the NSP, and the AER.

169. The arrangements for third party nondisclosure agreements could be included as part of the voluntary industry code discussed in the previous section, or be established through rules. There would benefits in establishing standard legal documentation in order to reduce costs.

6.5 Comments on regulatory cost benefit analysis

170. The table below sets out my high level comments on the potential outcomes of a regulatory cost benefit analysis. I consider the most promising option for the AEMC to pursue is a system for limited disclosure to third parties (Option 4). This appears to have the best potential to address the underlying issue (the need for improved quality and relevance of probative information provided to the AEMC) by enabling access to all confidential information by stakeholder representatives and experts. This option therefore seems to have the most potential to improve the credibility of the regulatory regime.

171. Assuming (as the AEMC states) that there will always be some legitimate commercial in confidence information, and this is material to a third party's ability to provide useful probative submissions to the AER, then none of the other options would be as effective as Option 4 although they may act to compliment Option 3.

[41] Assessment of proposed changes to the regulatory decision making process under the National Electricity Rules Report for the Energy Networks Association by Gilbert + Tobin, 8 December 2011.

Comments on regulatory cost benefit analysis for managing NSP confidentiality claims

	Option 1 Provide AER with more time to consider confidentiality claims in initial and revised regulatory proposals	Option 2 Clarify NER to reflect the NEL and/or common law position	Option 3. Codification to better define scope of legitimate confidential information	Option 4. System for limited disclosure to third parties
Benefits				
1. Improved quality and relevance of probative information				
1.1 Does option make available **all** confidential information to stakeholder experts?	No? – assuming there will always be some legitimate commercial confidence information that NSP should be able to protect	No? – assuming there will always be some legitimate commercial confidence information that NSP should be able to protect	No? – assuming there will always be some legitimate commercial confidence information that NSP should be able to protect	Yes? – assuming satisfactory third party disclosure arrangements can be established
1.2 Does option make available **some** additional confidential information (but not all) to stakeholder experts?	Potentially yes?	Depends – yes, if potential for AER to give less weight to confidential information encourages increased disclosure by NSP	Potentially yes?	Not relevant
2. Improved credibility of regulatory regime to stakeholders	Some improvement?	Some improvement?	Some improvement?	Significant improvement. Greater scope for disclosure of information where satisfactory arrangements can be established, particularly sensitive information could be made available to stakeholder experts for example. .

	Option 1 Provide AER with more time to consider confidentiality claims in initial and revised regulatory proposals	Option 2 Clarify NER to reflect the NEL and/or common law position	Option 3. Codification to better define scope of legitimate confidential information	Option 4. System for limited disclosure to third parties
Costs				
3. Upfront costs for developing new arrangements	Not significant – ongoing administrative costs for AER	Not significant	Moderate upfront cost to undertake codification	Moderate upfront cost to develop system of limited disclosure to third parties
4. Change in ongoing regulatory management costs for AER compared to status quo	Increased cost – AER now considering confidentially claims	Not significant	Not significant?	Not significant?
5. Change in regulatory management costs for NSP compared to status quo	Increased cost – NSPs now need to engage more with AER determination of confidentially claims	Increased cost – new issue for NSP to deal with	Lower costs? – assuming that code provides clearer guidance on how NSP treat confidential information	Modest costs in administering disclosure agreements

7. Framework and approach paper

172. This section sets out my opinion on the AER's proposed rule changes related to the framework and approach paper, the AEMC's initial position, and the question asked by the AEMC.

7.1 Background

173. The AER considers that:

- The framework and approach paper creates an inefficient three-stage consultation process on incentive schemes for distribution.
- The framework and approach paper is not binding in respect of incentive schemes, providing little benefit in the regulatory determination process and no regulatory certainty.
- It may wish to change or include a form of control mechanism, including to reflect a change in service classification after the framework and approach paper, but is prevented from doing so. This is because the form of control mechanism is set out and fixed in the framework and approach paper, with no ability for the AER to change or develop a new form of control mechanism.
- There is too much scope for service classifications to be amended (i.e. for "good reasons") which does not provide enough investment certainty.

174. To address its concerns, the AER proposes:

- removing consultation on the application of incentives schemes in the framework and approach paper, and
- allowing the AER to change the form of control mechanism, in addition to service classification, following the framework and approach paper but only if, after the framework and approach paper is published, unforeseen circumstances arise.

7.2 AEMC initial position

175. The AEMC's initial position is :

- The framework and approach paper stage should be optional, with the appropriate trigger to be considered further.
- Incentive schemes should remain part of the framework and approach paper. It may be appropriate to include in the paper the proposed sharing mechanism to allow consumers to be compensated where distribution assets are used to provide non-standard control services.

- The AER's proposal to use "unforeseen circumstances" as the trigger for allowing changes to a control mechanism or service classification set in the framework and approach paper appears to be broadly appropriate from a policy point of view. The Commission seeks submissions on this, and in particular whether any foreseeability element must be reasonable.
- More information is sought on how much time it is likely to take for a NSP to adjust its regulatory proposal for a revised control mechanism set by the AER in a draft regulatory determination.

7.3 Assessment

7.3.1 Framework and approach paper stage should be optional

176. I agree for the reasons[42] stated by the AEMC that if there are no material changes to all or some of components of the framework and approach paper, then it should not be necessary for there to be consultation on that particular component, and, potentially no requirement alt all for any framework and approach paper. That is, a framework and approach paper is only required; and its scope should be defined, where there are issues concerned with changes to control mechanism, incentives or service classification that positively need to be addressed.

7.3.2 Should incentive schemes remain part of the framework and approach paper?

177. The AEMC states that, as there has been reasonable stakeholder engagement on incentive schemes in the framework and approach paper process, it does not appear appropriate to eliminate these from the framework and approach paper altogether.

178. In my view, there are two separate issues:

- Is there a need for the AEMC to mandate consultation on incentive schemes?
- Should consultation be part of the framework and approach paper consultation process?

179. In my view, there is now a considerable degree of maturity as to how the incentive schemes should operate; and there is, and will continue to be, national convergence towards a relatively common set of incentive schemes.

180. Therefore, there should not be mandatory consultation on incentive schemes for each NSP. Given the increasing national convergence in incentive schemes, a better means for undertaking any review or

[42] Consultation on component(s) of the Framework and Approach paper do not provide any additional benefit and certainty. Not requiring consultation would lead to more flexibility and discretion in the regulatory determination process, as well as reduce administrative costs by making the process more efficient.

consultation on changes to incentive schemes may be a sector wide review covering all incentive schemes. Consultation through a Framework and Approach paper should be required only for changes to incentive schemes if the AER, the NSP or a third party considers that a review is warranted of the previous incentive scheme that applied, and the issues are not best dealt with through general (rather than specific) review.

181. In my view, the rules should be simplified to:

- Provide for a national review and consultation process, recognising national convergence of incentive schemes.
- Require early consultation by the AER with the NSP and also targeted stakeholder consultation to ascertain whether there is any perceived need for a review
- Create an obligation on the AER to undertake consultation on potential changes to incentive schemes if it is requested to do so by the NSP
- Enable the AER to undertake a review if it considers this would be in the long term interests of customers, taking into account the views of stakeholders, and
- Clarify that if no review is undertaken then the incentive schemes that applied in the previous regulatory period should continue in the forthcoming regulatory period

182. There is no need to require consultation on incentive schemes as part a framework and approach paper or through a separate process. This decision can be left to the AER.

7.3.3 Trigger for allowing changes to a control mechanism or service classification

183. The AEMC sought submissions in relation to the trigger for allowing changes to a control mechanism or service classification set in the framework and approach paper.

184. The AEMC sets out two options for triggering changes to service classification and potentially the form of price control. These are:

- Depart from the previous framework and approach paper in the event of “unforeseen circumstances”. This approach is proposed by the AER and the AEMC considers this approach is appropriate.
- DNSPs should have the ability to seek, and the AER to consider, a move away from the service classifications in the framework and approach paper, and extend this also to the form of control mechanism if there are persuasive arguments or material reasons to move away. This approach is proposed by Ausgrid.

185. In my opinion, best regulatory practice and the evolving environment in which DNSPs operate should facilitate review and changes in service classifications and/ or the form of control mechanism where justified. There may be a number of pressures to review service classifications arising from changes in the DNSP environment including developments in smart meters and related services, demand management, embedded generation, or changes in opportunities for contestability at the margins of DNSP operations. Best regulatory practice should allow for innovation and adaptation to such changing circumstances.

186. Therefore I consider that the need for a review of service classification and change could emerge due to a change in circumstances, or otherwise if there were persuasive arguments or material reasons to do so. Therefore, either the NSP or the AER should be able to trigger a review of service classifications or the form of control as part of the framework and approach paper process.

A further issue to be considered is the potential for competition. Currently, when considering service classification, the AER must have regard to the potential for development of competition in the relevant market and how the classification might influence that potential[43]. I note that there may be third parties (for example electrical contractors in regard to contestability opportunities[44]) who seek changes to service classifications. If there is no longer to be a regular review, then changes are required to retain the effect of the current rule (i.e. enabling the potential for competition to be considered). In my view, the appropriate change is to provide third parties with a clear pathway to apply to the AER for a review of service classifications as part of a framework and approach paper. An application for a review of service classifications by third parties could be against defined criteria set by the AER or in the rules.

187. Finally, I consider that there is no need for a review through the Framework and Approach paper where there are minor changes in control mechanisms and service classifications that reflect technical considerations.

188. In summary, I consider the rules should establish a process for consultation on control mechanisms or service classifications as follows:

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[43] Cl 6.2.2(c)(1) NER.

[44] See for example s2.4.2 of AER Final decision *Framework and approach paper Classification of services and control mechanisms* Energex and Ergon Energy 2010–15. The AER noted that “Submissions received from design consultants and construction contractors indicate that there are alternative providers available in Queensland to provide the design and construction of large connection assets service but the market was constrained due to the DNSPs limiting the entry of alternative providers to the market.“ Potential for such competition may evolve over time.

- Require early consultation by the AER with the NSP and also targeted stakeholder consultation to seek views as to whether there is any need for a review of control mechanisms or service classifications.
- Create an obligation on the AER to undertake a review if it is requested to do so by the NSP.
- Enable the AER to undertake a review if it considers this would be in the long term interests of customers
- Clarify that if no review is undertaken then the control mechanisms and service classifications that applied in the previous regulatory period should continue substantially unchanged in the forthcoming regulatory period
- Clarify that minor changes in control mechanisms and service classifications that reflect technical considerations and do not make substantive changes can be proposed in the initial regulatory proposal or decided by the AER in the draft regulatory determination without the need for a review.

7.4 Timing implications for a NSP to adjust its regulatory proposal for a revised control mechanism set by the AER

189. The AEMC requested information on how much time it is likely to take for a NSP to adjust its regulatory proposal for a revised control mechanism set by the AER in a draft regulatory determination.

190. In my experience, the types of analysis required by an NSP to adjust its regulatory proposal in response to a revised control mechanism could, depending on the nature of the change, include

- analysis of the change on revenues and returns of any changed risk allocation, in particular demand risk
- analysis of the desired change in the tariff for the services that are subject to the control mechanism, and
- potentially, operational effects (for example, if changes in tariffs have significant operational implications).

191. The time that it takes a business to undertake this analysis would vary significantly. First, the time will depend on the extent of change in the control mechanism. For example, minor refinements in the price control formula can be dealt with quite quickly; whereas a fundamental change in the price control (for example moving to a hybrid price / revenue cap) would take much longer. Secondly, businesses have different levels of capability and resources. It would therefore seem difficult to set a single timeframe that deals realistically with all situations. This means that if a single timeframe is to be set, it needs to be set conservatively, and assume a major change in the price control.

192. On balance, it may be better to include a principle-based rules as follows:

- Require early consultation between the NSP and AER at the outset of the determination process to determine whether there is a possibility of revisions in the control mechanism.
- Based on the nature of the possible change, the AER and NSP would be required to consult on and agree a decision timetable.

8. Material errors in determinations

193. This section sets out my opinion on the AER's concerns and proposed rule amendments where a material error arises, the AEMC's initial position, and the questions raised by the AEMC.

8.1 Background

194. Briefly, the AER raises three areas of concern with respect to revocation and substitution of regulatory determinations as a result of material errors:

- there may be the potential for a material error that is outside the currently prescribed list for distribution regulatory determinations;
- In transmission, uncertainty is created by the power to correct material errors caused by false and misleading information as there is no express limit placed on correcting this type of error "only to the extent necessary".
- There may be circumstances in which it is preferable or more appropriate to amend a regulatory determination, as opposed to revoking and substituting the entire regulatory determination.

195. The AER's proposed rule changes are to:

- replace the prescribed list of material errors in Chapter 6 with a more general reference to material errors or deficiencies
- limit changes related to false and misleading information under Chapter 6A "only to the extent necessary"
- have the ability to amend, in addition to revoke and substitute, regulatory determinations in response to material errors, and
- expand the circumstances for revoking and substituting regulatory determinations to address deficiencies (in addition to material errors) under Chapter 6A.

8.2 AEMC initial positions

8.2.1 Objectives

196. The NER must strike an appropriate balance between finality of the distribution or transmission determination that is intended to apply for the length of the regulatory control period, and for those determinations to be "correct" at the time they are made.[45] The AEMC's position on the objective for rules to correct material errors is as follows:

> *In respect of changes to regulatory determinations, the Commission is generally of the view that after the final regulatory determination is made it should only be able to be changed as a result of merits review outcomes or in very clear and exceptional circumstances. Therefore, the Commission is in favour of keeping the scope of the material error provisions narrow and focussed on "computational" errors or situations where a NSP has submitted false or misleading information.*

197. I agree with the AEMC's position on objectives for material errors. A narrow approach to defining material errors helps minimise regulatory costs and creates incentives on all parties to undertake proper scrutiny of the regulatory determination process.

8.2.2 Broadening definition of material errors and deficiencies

198. This section deals with the AER's proposed rule change to broaden the definition of material error.[46] The proposed new rule is as follows

> *The AER may only revoke or amend a distribution determination during a regulatory control period where it appears to the AER that:*
>
> - *the annual revenue requirement was set on the basis of information provided by or on behalf of the relevant Distribution Network Service Provider to the AER that was false or misleading in a material particular; or*
> - *there was a material error or deficiency in the distribution determination.*

199. The AER's rationale for this rule change proposal is:

> *It is conceivable that a material error may arise from errors outside the scope of the prescribed list of errors in Chapter 6.*

200. The AEMC's initial view is as follows:

[45] Assessment of proposed changes to the regulatory decision making process under the National Electricity Rules Report for the Energy Networks Association by Gilbert + Tobin, 8 December 2011, p 21.
[46] AER Rule change proposal, pp 96-97.

> *More support is required prior to broadening the types of material errors or deficiencies under Chapter 6 by which the AER may revoke and substitute regulatory determinations*

201. I consider that the AEMC had a clear policy intent in drafting the current rule 6.13(a). The AEMC stated that the rules:

> *...should ensure sufficient certainty with respect to the term 'material error'[47], and*
>
> - *acknowledge that the use of 'material error' is a well established term in law and constituted a material error of fact rather than judgement to ensure that revocation would only occur where it falls within the legal bounds of a 'material error'* [48]

202. Gilbert and Tobin in its advice to the ENA comment that[49]:

> *It is not clear from the AER Rule Change Proposal that the existing drafting in the NER is deficient in that the AER does not identify any "error" in a distribution or transmission determination that it considers it would have been appropriate to correct, but that it did not have the power to do so.*
>
> *The AER's proposal to remove the kinds of material errors or deficiencies that may be corrected through revocation and substitution obviously expands the circumstances in which the AER may select to address through revocation and substitution. The extent of these circumstances is unknown. It is also not limited to material errors, but extends to "deficiencies", and the precise nature of what may or may not be considered a "deficiency" is not clear. The potential breadth of what may constitute a "deficiency" is currently constrained in the existing provision because of the list of the kind of deficiencies that may be corrected. The AER"s proposal, if accepted, would remove that constraint and introduce significant uncertainty as to the potential operation of the revocation and substitution power.*

203. The current definition of "material errors or deficiencies" in s6.13 (a) (for which the AER may revoke and substitute a distribution regulatory determination during a regulatory control period) is clear and straightforward to interpret.[50] I note that "material error or deficiency" is not defined, and is open to interpretation by the AER.

204. My opinion in relation to this rule change is that AER has not made a case for change to the definition of "material error or deficiency": First, it has not provided any reason why the AEMC's original policy intent needs to be changed. Secondly, the proposed rule change reduces certainty as to the future application of rule 6.13 (a) but without any commensurate benefits in terms of promoting the national electricity objective. Thirdly, it does not identify any "error" in a distribution or transmission determination that it

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[47] AEMC Draft Rule Determination, pp 121-122; AEMC Final Rule Determination, pp 121-122.

[48] AEMC Draft Rule Determination, pp 121-122; AEMC Final Rule Determination, pp 121-122.

[49] Assessment of proposed changes to the regulatory decision making process under the National Electricity Rules
Report for the Energy Networks Association by Gilbert + Tobin, 8 December 2011.

[50] Material errors or deficiencies relate to a clerical error, an accidental slip or omission, a material miscalculation of figure or material mistake in describing any person, thing or matter referred to, a defect in form, or the regulatory determination being based on false or misleading information provided to the AER.

considers it would have been appropriate to correct, but that it did not have the power to do so. In other words, there is no evidence justifying the change.

8.2.3 Only to the extent necessary

205. This section deals with the AER proposed rule change to limit changes related to false and misleading information under Chapter 6A "only to the extent necessary".

206. The AER's rational for this rule change is that

> *...the ability in Chapter 6A for the final decision to be changed more than the extent necessary to correct an error, where that error is caused by the provision of false and misleading information, has the potential to undermine the finality of the decision making process by reopening matters not necessary for the correction of the error*

207. The AEMC's initial view in relation to this proposed rule change is as follows:

> *...the "only to the extent necessary" limitation should apply to false and misleading information under Chapter 6A - this would align Chapter 6A with Chapter 6 and provide certainty and finality*

208. Gilbert and Tobin advice to the ENA states[51]

> *...in the absence of an explicit provision restricting the AER to only varying the revoked determination to the extent necessary to correct for issues arising from reliance on false or misleading information, it is likely that the AER would be impliedly restricted in this way given the broader national electricity objective and the revenue and pricing principles. Relative to the other issues raised by the AER"s proposed amendments to the revocation and substitution provisions in the NER, this issue does not appear to be of particular importance.*

209. I support the AEMC's initial view. It is consistent with the AEMC's objective (with which I agree) to establish a narrow approach to defining material errors.

8.2.4 Ability to amend, in addition to revoke and substitute, regulatory determinations

210. This section deals with the AER proposal to expand the circumstances for revoking and substituting regulatory determinations to address deficiencies (in addition to material errors) under Chapter 6A.

211. The AER states that:

> *In the event an error is to be corrected, the AER is not afforded a power to 'amend' a distribution or transmission determination, it is conceivable there may be circumstances where it is more appropriate*

[51] Assessment of proposed changes to the regulatory decision making process under the National Electricity Rules Report for the Energy Networks Association by Gilbert + Tobin, 8 December 2011.

> *or preferable to do so rather than to 'revoke and substitute' the entire distribution or transmission determination.*

212. The AEMC's initial view in relation to this proposed rule change is as follows:

> *It is unclear how amending regulatory determinations would differ in practice from revoking and substituting - but the Commission agrees that this will impact unfavourably on the availability of merits reviews.*

213. There are two issues raised by this proposed rule change: the impact on the availability of merits review; and whether there are any administrative or benefits from allowing amending of a regulatory determination.

214. In my opinion, it would not be appropriate for the AEMC to make rule changes if the only, or major, effect would be to reduce rights to merits review. It is my understanding that appeal rights are a policy matter for governments, not the AEMC.

215. The only possible benefit that I can identify for allowing "flexibility to amend" is some administrative cost benefit. In relation to whether there are any such benefits from allowing amending of a regulatory determination, Gilbert and Tobin[52] note that:

> *In terms of whether the AER requires "flexibility to amend", instead of revoking and substituting a determination, it would appear from the examples [analysed by Gilbert and Tobin] that where the AER has revoked and substituted determinations under the provisions that existed in the National Electricity Code, the requirement to remake has not practically operated as a significant barrier*

216. In my opinion, if AEMC investigation confirms that there potential administrative benefits, then I consider that amendment should only be allowed with the consent of the relevant NSP. This would protect the NSP against the loss of appeal rights.

8.2.4.1 Rule 6A.15 to reflect the narrow scope of material errors in rule 6.13

217. This section deals with the AER proposal to amend rule 6A.15 to reflect the narrow scope of material errors in rule 6.13.

218. The AEMC's initial view is that:

> *It may be more appropriate for rule 6A.15 to reflect the narrow scope of material errors in rule 6.13 – this would result in more certainty and finality for the AER and NSPs, although less flexibility for the AER.*

---

[52] Assessment of proposed changes to the regulatory decision making process under the National Electricity Rules Report for the Energy Networks Association by Gilbert + Tobin, 8 December 2011.

219. In my opinion, this change would be appropriate for the reason stated by the AEMC, and because there is no reason why TNSPs should be treated differently from DNSPs. The definition of material errors or deficiencies in rule 6.13 (a) should be adopted in an amended rule 6A.15.

9. Timeframes for cost pass through, contingent projects and capex reopeners

220. This section sets out my opinion on the AER's concerns and proposed rule amendments to the timeframes for cost pass throughs, contingent projects and capex reopeners, the AEMC's initial position and the question raised by the AEMC.

9.1 Background

221. The AER notes that the NER currently imposes hard deadlines for it to assess positive pass through applications, contingent projects and capex reopeners. In the case of positive pass through applications, a 60 day time limit is imposed, while for contingent projects and capex reopeners the limit is 30 days. The AER suggests that that, while these timeframes may be adequate in most cases, circumstances may arise in the future which require an extension of the assessment timeframe.

222. The AER proposes a common default decision-making period of 40 days from the date the application is received for positive pass throughs, negative pass throughs, contingent projects and capex reopeners. For complex or difficult applications or where the AER requires further information from NSPs, the AER proposes to extend this decision-making period by an additional maximum period of 60 business days.

9.2 AEMC initial position

223. The AEMC's initial position it that a "stop the clock" mechanism should be explored further.

> *The "stop the clock" mechanism may be appropriate for addressing complex pass through and capex reopener applications.*
>
> *"Stop the clock" should not be applied to contingent project applications as it is unclear when complex circumstances could arise for these types of applications but it seeks submissions on this.*
>
> *Submissions are sought on the timeframes prescribed for the period between the event and the submission of an application in respect of it, and the possibility of any other options such as a NSP providing a notice of intent for making an application.*
>
> *Consideration of the time between an event occurring and the submission of an application to the AER in respect of it will require consideration of how an "event" is characterised. This may link to the rule change request on pass throughs, submitted by Grid Australia, which the Commission is also currently considering.*

9.3 Assessment

224. The core objective for the rules for cost pass throughs, contingent projects and capex reopeners timeframes can be summarised as follows:

> *[The NSP's requirement to recover its efficient costs] needs to be balanced with the need for certainty and finality of AER decisions which is an important contributor to the incentives that make up the current framework[53].*

225. In determining the appropriate rule design, I consider that the AEMC must turn its mind to fundamental design questions around managing risk and uncertainty. The essence of this question is illustrated by the following simple example.

226. The AEMC has a choice as to whether the rule design for timeframes for cost pass throughs, contingent projects and capex reopeners should:

- be effective in most circumstances, but it is acceptable for there to be a rules breach in an exceptional circumstance (Option 1), or
- always (or nearly always) be effective, including in any reasonably foreseeable exceptional circumstance (Option 2).

227. The challenge with rules in this area is that from time to time, exceptional circumstances are likely to arise. These circumstances occur when the decision involves large, controversial or complex matters or new and unusual situations. The AEMC discussion notes recent examples of exceptional circumstances[54] which have lead to time extensions and In my view, it is inevitable that in future years, other exceptional circumstances will arise.

228. Under the first option, the rules can be relatively simple. For example, the proposed stop the clock mechanism might be a sensible approach. Provided the appropriate parameters are selected, then such a rule should operate to achieve the rule objective most of the time, but will probably not be effective (the rules will be breached) in some exceptional circumstances. I consider that this could be a valid approach, but the AEMC and participants should understand the limitations of this rule design.

229. Under the second option, the rules would need to be more complex. The rule design would need to consider in detail how exceptional circumstances are recognised; the potential implications of different

[53] AEMC Directions Paper, p 149.

[54] The AEMC notes that the NSW DNSPs which were provided an additional six months to submit cost pass through applications in respect of costs associated with the sale of their respective retail businesses; and the Cyclone Yasi, where the AER granted Ergon Energy an additional 40 business days to submit an application; see AEMC Directions Paper, p 150.

types of events, what reasonable time extensions should be granted, and the balance between rules and AER discretion to make decisions. If the AEMC and participants wish to manage risk and uncertainty along the lines of the second option, then I consider that the AEMC would need to undertake a specific rules review which involved appropriate studies and people with high levels of technical and risk management expertise

230. On balance I am inclined to recommend a rule design along the lines of the first option. The rule (or the AEMC's rule decision) could state the expectation about the probability of the rule being complied with. (For example that the rule has been designed to be effective in relation to (say) 95% of anticipated cost pass through applications).

231. In addition I recommend monitoring of the performance of these rules. Statistics should be collected and published on the number of cost pass through, contingent projects and capex reopener applications that are processed within the rule deadline and how many exceed the deadline.

Annex 1 How the Principles of good regulatory practice are reflected in the National Electricity Law

Principles of good regulatory practices	National Electricity Law
Proportionality – Regulators should only intervene when necessary. Remedies should be appropriate to the risk posed. Costs should be identified and minimised.	Under section 71E, the Tribunal only grants leave when there is a serious issue to be heard and determined and a financial threshold (set out in section 71F) is met. This means frivolous and vexatious grounds will not meet the thresholds. Clause 42 in Schedule 2 sets out that the National Electricity Rules should be construed to full extent of legislative power (but should not exceed that).
Accountability – regulators must be able to justify decisions and be subject to public scrutiny.	As above – AER, AEMC, AEMO and Court/Tribunal processes are open to parties to review aspects of the regulators' decisions and provide their views on these decisions – section 16(1) provides for public consultation of determinations before they are made, section 45 allows the AEMC to consult on its proposals, section 70 allows for judicial review of AEMC and AEMO decisions and section 71B allows for merits review by persons aggrieved by the AER's determination. The AEMC is required under section 102 to set out in its Rule determination the reasons for its decision. **Judicial review**: Under section 70, applications for judicial review can be made by 'a person aggrieved' by the decision of the AEMC or AEMO made under the Rules or Law. Under section 71, a person who is a party to a Rule dispute may appeal on a question of law. **Merits review**: Under section 71B, an affected or interested person or body, with the leave of the Tribunal, may apply for review of a reviewable regulatory decision. In previous merits reviews, where the service provider applied for review, interveners joined the proceedings, including the relevant state energy minister, council groups and users of the network. The minister and the regulated network service provider (if they are not the applicant), do not need the leave of the Tribunal (under section 71J). Interveners do require leave, which will typically be granted subject to the party having previously raised the issue in submissions before the AER (see section 71G). Interveners can raise new grounds (see section 71M).
Consistency – Government Rules and standards must be joined up and implemented fairly.	Section 7 set outs the National Electricity Objective pursuant to which regulators are required to make decisions under the Law consistently in line with that objective (in accord with section 16). The objective 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 range of factors including price, quality, safety and reliability of electricity supply.

Principles of good regulatory practices	National Electricity Law
	Similarly, section 88 requires the AEMC to make a Rule if it is satisfied that the Rule complies with the National Electricity Objective. Under section 91a, the AEMC may make a more preferred Rule in certain cases where it is satisfied that its preferred Rule is more in line with the National Electricity Objective than the proposed Rule.
Transparency – Regulators should be open and keep regulations simple and user friendly	As above for accountability.
Targeting – Regulation should be focused on the problem and minimise side effects	As above - under section 71R, the Tribunal must only have regard to material that was before the AER unless it considers that new information or material would assist on an aspect of its determination. Under section 71O, a matter that was not raised before the AER cannot be raised before the Tribunal by a party.

Annex 2 How the regulatory design factors are reflected in the National Electricity Law

Regulatory Design Factors	National Electricity Law
Provide opportunities for engagement by regulated businesses and interested stakeholders	**AER processes**: Under section 16(1), the AER is required to inform the regulated network service provider, any affected Registered participants and AEMO of material issues under consideration in the context of determinations and those parties are given a 'reasonable opportunity to make submissions' in respect of determinations before they are made. The AER is required to publish decision on its website (Schedule 2, clause 31AB). **AEMC processes**: Under section 45, the AEMC may consult with any person or body that is considers appropriate when it conducts a review the operation and effectiveness of the National Electricity Rules. In relation to Rule changes, any person or body can make submission or comments under section 97. Submissions may be published by the AEMC (section 108). The AEMC can also hold public hearings before the draft Rule determination (see section 98). Draft Rule determinations are published (section 99), parties can make submission on the Draft Rule determinations (section 100) and the AEMC may hold public hearings before the final Rule determination (section 101). Once finalised, the Rule must be published on the website and made available to the public (section 105). **Merits review**: Under section 71B, an affected or interested person or body, with the leave of the Tribunal, may apply for review of a reviewable regulatory decision. In previous merits reviews, where the service provider applied for review, interveners joined the proceedings, including the relevant state energy minister, council groups and users of the network. The minister and the regulated network service provider (if they are not the applicant), do not need the leave of the Tribunal (under section 71J). Interveners do require leave, which will typically be granted subject to the party having previously raised the issue in submissions before the AER (see section 71G). Interveners can raise new grounds (see section 71M).
Reduce regulatory risk and probability of error	Under section 7A(2) of the Law, the revenue and pricing principles require that a regulated service provider be provided with an opportunity to cover at least its efficient costs. In this way, the revenue and pricing principles seek to reduce the downside risk of regulatory error (i.e., reduces the risk that a regulated service provider will under-recover on its costs). More explicitly in section 7A(5) of the Law, a price or charge for a direct control network service should allow for 'a return commensurate with the regulatory and commercial risks' involved in providing the service. Similarly, the AEMC under section 88B must take account of the revenue and pricing principles in making a Rule in certain cases.
Promote timely decisions	Time limits imposed on the merits review proceedings ensure that decisions are made within a relatively short period from the time at which review is sought. Under section 71D, relevant people have 15 business days after the reviewable regulatory decision to apply for merits review. Under section

	71Q, the Tribunal is to use its best endeavours to make a determination within 2 months after leave is granted.
Facilitate reasonable administrative costs	Under section 71R, the Tribunal must only have regard to material that was before the AER unless it considers that new information or material would assist on an aspect of its determination. Under section 71O, a matter that was not raised before the AER cannot be raised before the Tribunal by a party. Further, under section 71P, the ability to remit the decision back to the AER allows for those with the expertise in modelling etc to apply the Tribunal's decision. The Tribunal can also require the AER or AEMO to give information or otherwise assist under section 71W.

Annex 3 – Legal Advice on proposed changes to the capital and operating expenditure factors and requirement to publish material prior to a final decision)

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Memorandum of advice

15 April 2012

To	Garth Crawford, Energy Networks Association
From	Catherine Dermody
Matter No	1013538
Subject	**AER proposed Rule change: Advice re various regulatory process issues (proposed changes to the capital and operating expenditure factors and requirement to publish material prior to a final decision)**

1. Introduction and request for advice

The Rule change proposal[55] lodged by the Australian Energy Regulator (**AER**) with the Australian Energy Market Commission (**AEMC**) in September 2011 seeks to amend the Rules relating to the economic regulation of network services. The Rule change proposal includes amendments to the regulatory decision making processes set out in the National Electricity Rules (the **Rules**). Specific to this advice, a discrete area that is the subject of the AER's Rule change proposal relates to the capital expenditure (**capex**) factors[56] and operating expenditure (**opex**) factors[57] for both electricity transmission and distribution.

The capex and opex factors are relevant to the AER's engagement with the regulatory proposals lodged by Network Service Providers (**NSP**) and more specifically, list the matters that the AER is required to have regard to when determining whether or not it is satisfied that the capex and opex forecasts proposed by a NSP reasonably reflect the required expenditure. The relevant decision-making rule provides that if the AER is satisfied that the

[55] Australian Energy Regulator, *Economic Regulation of Transmission and Distribution Network Service Providers: AER's Proposed Changes to the National Electricity Rules – Rule Change Proposal*, September 2011, p 34 (**AER Rule Change Proposal**).

[56] Clauses 6.5.6(e) and 6A.6.6(e).

[57] Clauses 6.5.7(e) and 6A.6.7(e).

capex or opex forecast does reasonably reflect the capex and opex criteria respectively, the AER must accept the forecast, and if the AER is not so satisfied the AER must reject the forecast and determine a substitute value.

Broadly speaking, the AER Rule change proposal seeks to alter the matters the AER must have regard to in making its determination on the capex and opex forecast amounts, in particular by removing the first three expenditure factors from the capex and opex provisions. In addition, in exercising the decision-making rule that applies to the AER's assessment of the capex and opex forecast amounts, the AER's Rule change proposal (if accepted by the AEMC) could have the effect of directing the AER to give primacy to its own analysis, above the information provided in or accompanying a NSP's regulatory proposal.

We have been asked to consider the legal implications which may arise from the AER's proposed Rule change to:

- move the first three expenditure factors within the specific capex and opex provisions to the general provisions on regulatory process in Part E of Chapters 6 and 6A the Rules respectively, and to change the requirement for the AER to "consider" rather than "have regard" to NSPs' proposals and written submissions; and
- remove the requirement on the AER to publish the analysis it has regard to in making its draft and final decision as previously specified within the third expenditure factor (which is expressed in slightly different ways in Chapter 6 and 6A).

Before assessing these proposed Rule changes, the current Rules and the AER's proposed changes are set out below in more detail.

2. The current Rules and the AER's proposed changes

Before turning to the issues to be considered, it is logical to first consider the Rules as expressed in their current form, and then the AER proposed changes to the Rules.

The current Rules

The capex factors are set out in clauses 6.5.7(e) and 6A.6.7(e) and the opex factors in clauses 6.5.6(e) and 6A.6.6(e). As stated above, the capex and opex factors are matters which the AER must have regard to in determining whether to approve or reject the capex and opex forecasts in a NSP's regulatory proposal. There are a number of factors to be taken into account within those provisions. The AER's proposed Rule change seeks to remove and alter the first three capex and opex factors, which are referred to by the AER as "procedural" or "process" factors.[58]

Clause 6.5.6(e), which prescribes the operating expenditure factors to be applied in assessing the distribution NSP's regulatory proposal, is in the following terms:

> In deciding whether or not the *AER* is satisfied [of the forecast of required operating expenditure], the *AER* must have regard to the following (the operating expenditure factors):
>
> (1) the information included in or accompanying the *building block proposal*;
>
> (2) submissions received in the course of consulting on the *building block proposal*;
>
> (3) analysis undertaken by or for the *AER* and *published* before the distribution determination is made in its final form;....

[58] See for example: AER Rule Change Proposal, p 37.

Clause 6.5.7(e) is in the same terms for capex expenditure factors.

The opex and capex expenditure factors contained in the Chapter 6A for transmission are in relatively the same terms except for subclause (3) which provides that the AER must have regard to analysis which is undertaken by or for the AER prior to *or as part* of the draft decision or the final decision. Clause 6A.6.6(e) provides:

> In deciding whether or not the *AER* is satisfied [of the forecast of required operating expenditure], the *AER* must have regard to the following (the *operating expenditure factors*):
>
> …
>
> (3) such analysis as is undertaken by or for the *AER* and is *published* prior to or as part of the draft decision of the *AER* on the *Revenue Proposal* under Rule 6A.12 or the final decision of the *AER* on the *Revenue Proposal* under Rule 6A.13 (as the case may be);...

The AER's proposed changes

The AER Rule change proposal relocates and amends the first three expenditure factors to Part E of Chapters 6 and 6A the Rules respectively, which contains general provisions on regulatory process and procedure.[59]

For instance in distribution, clause 6.10.1, which forms part of Part E and sets out the AER's decision making process in respect of the draft distribution determination, would be amended by the AER's proposal in the following manner (insertions shown in blue and deletions in red and strikethrough): [60]

> Subject to the Law and rule 6.14(a), the AER must:
>
> (a) consider any written submissions made ~~under~~ in accordance with rule 6.9;
>
> (b) consider any regulatory proposal submitted under rule 6.8 or 6.9;
>
> (c) have regard to analysis undertaken by or for the AER; and
>
> (d) ~~must~~ make a draft distribution determination in relation to the *Distribution Network Service Provider.*

Clause 6.11.1 which sets out the AER's decision making process in respect of the final distribution determination is also proposed by the AER to be amended in the same terms.

In respect of transmission, clause 6A.12.1 which provides the factors the AER is to consider in the making of the draft decision, and clause 6A.13.1 which is relevant to the making of the final decision, have been amended to reflect the same terms of clause 6.10.1 referred to above.

The AER's Rule change proposal not only relocates those factors from the specific provisions concerning opex and capex forecasts to the general provisions on regulatory process, but also seeks to:

- amend subclauses (1) and (2), so that the AER "must consider" written submissions and any regulatory proposal, (whereas under the current Rules, the AER "must have regard" to those factors in the capex and opex provisions); and
- amend subclause (3) to remove the reference to the publication of the analysis.

[59] AER Rule Change Proposal, pp 33-37.

[60] Mark up reflects amendments made by AER to current Rules contained AER's proposed changes to the National Electricity Rules – Complete Chapter 6 Draft Rules, September 2011.

The amendment to subclause (3) is more significant to Chapter 6 compared to Chapter 6A, which requires that analysis undertaken by or for the AER to be published prior to or as part of the draft decision or the final decision (as the case may be).

Rationale for the AER's proposed Rule change

The AER provides two primary reasons for its proposed Rule change to the capex and opex factors.

First, the AER considers that the first three expenditure factors list matters that are procedural in nature and do not substantively add to an assessment against expenditure criteria. They say that this creates confusion as to whether specific weight must be given to specific factors and how that is to be balanced with the other factors.[61] The AER contends that despite the proposed relocation the AER is still required to consider these matters as part of its overall decision making requirements. The changes are said to co-locate procedural and substantive matters, and "allow for the separation of the underlying analysis, supporting information and relevant material that shed light on the key drivers of the expenditure criteria contained in proposals and submissions".[62]

Second, the AER considers that expenditure factor three which requires the AER to consider its own analysis if it is published prior to the making of the final decision has the potential to make decision making processes unworkable within the prescribed timeframes as a result of a cycle of publishing analysis, prompting a submission which in turn requires further analysis and so forth.[63] It says that the relevant analysis will be made available as part of the reasons for the AER's decisions.[64]

3. Consideration of issues

Following from the AER's proposed changes referred to above, we have been asked to consider whether:

- relocation of the first three expenditure factors to Part E of Chapter 6 and 6A of the Rules respectively, and changing the requirement on the AER to "consider" those first two expenditure factors: and
- the removal of the requirement to publish the analysis the AER has regard to in making its draft and final decision within the third expenditure factor,

will have any significant implications on regulatory process and outcomes.

3.1 Shifting of first three expenditure factors to Part E of Chapter 6 and 6A of the Rules

The first issue to consider is the legal implications which follow from the AER's proposed amendment to move the first three expenditure factors to Part E of Chapter 6 and 6A of the Rules respectively, and require that the AER "consider" the NSP's regulatory proposal or revised proposal, as compared to the AER being required to "have regard to it". This first issue contains two parts – that is the relocation, and the amendment.

We consider that the first three expenditure factors are not clearly strictly procedural in nature as the AER contends. Determining whether a clause is procedural or substantive to the regulator's decision making process requires a consideration of the Rule in its entirety, not the clauses in isolation. In light of the overarching requirement to "have regard" to the capex and opex factors, the first three expenditure factors are to be viewed as *fundamental elements* in the decision making process of the AER in deciding whether or not it is satisfied that the forecast opex or capex amounts reasonably reflect the expenditure criteria so to form a view as to whether it is required to accept or reject the proposals. This approach is made apparent in case law authority, which confirms that when a decision making authority is entrusted with a function to "have regard" to certain factors, those factors are not passive considerations, but mandatory elements to be factored into the relevant decision to be made.

[61] AER Rule Change Proposal, p 34.

[62] AER Rule Change Proposal, p 37.

[63] AER Rule Change Proposal, p 34.

[64] Clauses 6.12.2 and 6A.14.2. See AER Rule Change Proposal, p 37.

In the Supreme Court decision of Western Australia, *Re Dr Ken Michael AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor* (2002) 25 WAR 511, Parker J (with whom Malcolm CJ and Anderson J agreed) opined at [55]:

> It is clear that an expression such as "have regard to" is capable of conveying different meanings depending on its statutory context. In s 2.24, the phrase "must take the following into account" is apt to convey as an ordinary matter of language that the Regulator must not fail to take into account each of the six matters stipulated in (a)-(f), and by (g) any other matter the Regulator consider relevant. If anything, "take into account appears, as a matter of language, little different from "have regard to". <u>Indeed, in *R v Hunt* the expression "have regard to" was understood as requiring that the specified matters be taken into account</u>. The matters specified in (a)-(f) appear <u>by their nature, to be highly material to the task of assessing a proposed Access Arrangement, given the legislative purpose and objects of the Act and the Code in this regard.</u> It is difficult to conceive that it could have been intended that the Regulator might decide to give no weight at all to one or more of the factors stipulated in s 2.24(a)-(f). <u>In my view, in the context of the Act and the Code, the Regulator is required by s 2.24 to take the stipulated factors into account and to give them weight as fundamental elements in assessing a proposed Access Arrangement with a view to reaching a decision whether or not to approve it.</u> (Emphasis added)

The phrase, "must have regard" has also been expressed to mean that the matters identified must be the focal point of the decision-making process.[65]

The requirement to "have regard" to the first three expenditure factors transforms their otherwise procedural content to form part of the substantive matters relevant to the AER's decision making in respect of determining whether or not it is satisfied that the proposed forecast reasonably reflects the required expenditure. Therefore, the current Rules operate to require the AER to take the specified information, submissions and analysis into account and to "give them weight as fundamental elements" in assessing the forecast expenditure with a view to reaching that particular decision. The expenditure factors listed are evidentiary matters which constrain and guide the judgment of the AER in accepting or rejecting the capex and opex forecasts.

Consistent with the analysis provided above in *Re Dr Ken Michael,* it is appropriate to refer to the broader decision making purpose affected in determining the significance of proposed amendments. The importance of the capex and opex forecasts is in the determination of the overall regulated revenue amounts. In light of the requirement on the AER to accept those amounts where it is satisfied on the material before it that the forecasts are consistent with the requirements of the Rules and to reject those amounts where it is not so satisfied, it is clearly appropriate that the AER be required to give the material before it on those forecast amounts weight as fundamental elements in making its decision. Contrary to the AER's contentions referred to above, the current process required by the Rules delivers certainty as to the matters to which the AER must have regard in making its determination that is a consideration of each of the matters equally.

Under the current Rules, the AER is not directed as to what material it should give primacy. It is clear that the AER can only substitute a forecast capex or opex value where it has formed a view that the NSP's forecast is not consistent with the Rule requirements. However, this is not equivalent to a requirement that the AER give the NSP's proposal primacy in assessing the forecast amounts. Under the AER's proposal, the AER would be required to take into account or have regard to, the analysis undertaken by or on behalf of the AER, and *consider* the information in the NSPs proposals and written submissions. In light of general statutory interpretation principles it would be imprudent to underestimate the change in expression from "have regard" to" to "consider". Those principles indicate that all words or phrases must prima facie be given some meaning and effect, and that conclusion is even more compelling if the phrase in question has been altered by amendment.[66]

[65] See *Evans v Marmont* (1997) 42 NSWLR 70 at 79; *Zhang v Canterbury City Council* (2001) 51 NSWLR 589 at 602, [71]-[75].

[66] D C Pearce and R S Geddes, Statutory Interpretation in Australia (2011, 7th ed) Lexis Nexis, p 49.

It follows then, that a possible legal interpretation of the AER's proposed rule change is that the AER would be required to give primacy to its analysis. This is a material shift from the current position in which the information in the NSPs proposal, the material in submissions by stakeholders and the AER's analysis are to be treated equally. It is also contrary to the position of the Australian Competition Tribunal (the **Tribunal**) which affirmed that it is the material before the AER, and in particular the material submitted by the service provider, that will fundamentally determine whether the AER can be satisfied as to the service provider's capex and opex forecasts.

In *Application by Ergon Energy Corporation Limited* [2010] ACompT 6, the Tribunal has commented that it is the service provider's "prime responsibility" to provide information to the AER for the AER to consider and evaluate. It also stated that a service provider has a "critical role to play" in providing information to the AER to assist the AER in making a decision which reflects the national electricity objective and revenue and pricing principles. The Tribunal made the following comments in the particular circumstances of that application (at [49]-[50]):

> The Tribunal accepts that Ergon Energy had the *prime responsibility* to provide information to the AER for the AER to consider and evaluate.
>
> <u>Ergon Energy had a *critical role to play in providing information*</u> to the AER to assist the AER in making a distribution determination which reflects the national electricity objective and the revenue and pricing principles. Having failed to do so adequately in relation to other costs, we cannot characterise the AER's decision in relation to other costs as unreasonable. Nevertheless, as indicated above, the AER, in the circumstances of this case, should have made further enquiry from Ergon Energy.
>
> This is not to say that the concepts of onus or burden of proof are to be adopted in the present context. <u>The *focus is upon the material placed before the AER, or upon the material available to the AER*, to determine whether AER can or should be satisfied of a particular matter</u>. (Emphasis added)

In summary, the following important points are relevant to a consideration of the AER's proposal with respect to the capex and opex factors:

- the requirement to give fundamental weight to information included in or accompanying the revenue proposal and submissions received in the course of consulting on the revenue proposal is removed. Under the AER's proposal, the AER is merely required to "consider" this material; and
- the requirement to have regard to the information mentioned above, together with the analysis undertaken by or for the AER *in the context* of making the specific decision on whether the AER is required to accept forecast capex or opex amounts is removed. Under the AER's proposal, this information is only required to be considered, or, in the case of analysis undertaken by or for the AER, regard to be had to it, in the making of the final decision.

The removal of those requirements will likely affect the decision making process of the AER. Specifically, if the AER's proposed amendments were accepted, the Rules could operate such that they may require the AER to give primacy to its own analysis, relative to the weight it would be required to give to the material in a NSP's regulatory proposal.

3.2 Consultation on material relied on by the AER in the final determination

The second issue to consider concerns the legal implications which may follow from the AER's proposed amendment to the Rules to remove the requirement that the AER must have regard to analysis relied upon which is published prior to making of the draft and final determination.

Under the AER's proposal, the AER is to have regard to such analysis as has been undertaken, as opposed to having been undertaken <u>and</u> published. As referred to above, this consideration is more relevant to Chapter 6, as in Chapter 6A, the requirement is analysis undertaken by or for the AER to be published prior to or as part of the draft decision or the final decision (as the case may be).

Section 16(1) of the National Electricity Law (**NEL**)[67], prescribes the manner in which the AER is to perform the AER economic regulatory functions or powers. It is expressed in the following terms:

> The AER must, in performing or exercising an AER economic regulatory function or power—...
>
> (b) if the function or power performed or exercised by the AER relates to the making of a distribution determination or transmission determination, ensure that the regulated network service provider to whom the determination will apply, any affected Registered participant and, if AEMO is affected by the determination, AEMO, are, in accordance with the Rules—
>
> (i) informed of material issues *under consideration by the AER*; and
>
> (ii) given a reasonable opportunity to make submissions in respect of that determination *before it is made*. (Emphasis added)

Section 16(1) is expressed in mandatory, not permissive terms, as construed by the words "must" and "ensure". It follows then, that the AER must make available to the NSP, and where relevant, other stakeholders, all analysis that is material to the making of its final decision prior to that final decision being made in order that the NSP can respond to that material. In making a final determination, if the AER has had regard to analysis that it has not made available to the relevant NSP, and therefore not brought to the attention of NSPs and stakeholders, such conduct would be contrary to section 16(1) of the NEL.

The AEMC in its Directions Paper which responds to the AER's Rule change proposal considered that that: [68]

- the Rules could be clarified to make it clear that there is an obligation on the AER to publish its analysis with its draft or final regulatory determinations, but no obligation to do so prior to this; and
- scrutiny of material relied on in the final regulatory determination by the AER which was not relied on for the draft determination (and not published by the AER, or the subject of submissions) would be through merits review.

However, those proposals could be considered to be contrary to a number of provisions in the NEL.

First, the requirement in section 16(1) that the AER is *required* to inform the relevant NSP and other parties of matters that are material to the AER's decision and be provided with an opportunity to respond to those issues, must logically occur before a final decision is made.

Second, the evidentiary limitations in the NEL that apply to merits review. Specifically, that the Tribunal may only have regard to "review related matter" in determining whether a ground for review in a merits review application has been made out (section 71R(6)). In broad terms this term "review related matter" has been interpreted to be the material that was before the AER when it made its final determination and, in certain circumstances, material referred to in materials that have been provided to the AER.[69] If the AER was not required to make available material until the publication of its final decision, material responsive to the AER's material would not have been submitted by the NSP or any other relevant stakeholder, and therefore it would be difficult to have any meaningful merits review of the matter. These evidentiary limitations mean that scrutiny of material relied on by the AER and not published, or otherwise made available to the NSP and other relevant stakeholders cannot be through the merits review process.

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[67] *National Electricity (South Australia) Act 1996* (SA), Schedule – 'National Electricity Law'.

[68] AEMC Directions Paper, p 32.

[69] See for example, *Application by Jemena Gas Networks (NSW) Ltd No 3* [2011] ACompT 6, [101] – [103]. This case considers what constitutes "review related matter" in section 261(7) of the National Gas Law, which is expressed in the same terms as in the National Electricity Law.