Ergon Energy Corporation Limited

Submission on the *Electricity Network Regulation* Issues Paper

Productivity Commission

16 April 2012

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1. INTRODUCTION

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider (DNSP) in Queensland, welcomes the opportunity to provide comment to the Productivity Commission on its *Electricity Network Regulation Issues Paper* (Issues Paper).

Ergon Energy generally supports the application of robust benchmarking techniques to assist in assessing the efficiency of network performance and informing regulatory decisions, provided such benchmarking takes into account different network characteristics and operating environments. Benchmarking of DNSPs is an inherently difficult task given the varying costs facing DNSPs across the National Electricity Market (NEM) and the lack of consistent, high quality data. Ergon Energy considers that more meaningful comparisons could be made following the development of a better, more consistent dataset across the industry, including agreement on the fundamentals of the benchmarking approach (i.e. what is an input and what is an output). Importantly, Ergon Energy does not consider that the National Electricity Rules (the Rules) place any limitation on the use of robust benchmarking by the Australian Energy Regulator (AER).

In addition, Ergon Energy believes that benchmarking should not be considered an appropriate substitute for a detailed evaluation of a DNSP's regulatory proposal. As is currently the case, benchmarking techniques should be only one factor in determining a DNSP's efficient and prudent forecast expenditure during the regulatory determination process.

Ergon Energy is a member of the Energy Networks Association (ENA), the peak national body for Australia's energy networks. The ENA has prepared a comprehensive submission addressing each of the questions posed by the Productivity Commission in its Issues Paper. Ergon Energy is fully supportive of the arguments contained in their submission.

Ergon Energy has structured this submission into the following sections:

- Section 2 outlines our key issues in relation to the Issues Paper; and
- Section 3 outlines our detailed comments in response to the consultation questions posed by the Productivity Commission.

Ergon Energy is available to discuss this submission or provide further detail regarding the issues raised, should the Productivity Commission require.

2. KEY ISSUES

This section discusses Ergon Energy's key issues in response to the concepts explored in the Issues Paper. Ergon Energy believes these issues should be given due consideration by the Productivity Commission.

2.1 Regulatory Framework

Ergon Energy is concerned that the Issues Paper poorly explains a few fundamental regulatory concepts. Given the terms of reference require the Productivity Commission to examine the use of benchmarking under the regulatory framework, Ergon Energy believes it is vital for the Productivity Commission to have a clear understanding of the concepts involved. For example, the Issues Paper states that "the AER sets five-year revenue or price ceilings" when the regulatory control period for DNSPs is a period of not less than five regulatory years.[1] The Issues Paper also refers to the "dominance of the building blocks approach" when discussing the AER's concerns about being restricted to a line-by-line assessment of a DNSP's regulatory proposal.[2] As noted on page 20, the building block approach is the only approach permitted under Chapter 6 of the Rules (albeit, the AER must have regard to benchmarking and other factors as part of the application of this approach).

2.2 Using Benchmarking to Assess Regulatory Performance

2.2.1 Challenges of Benchmarking

There are numerous challenges associated with benchmarking which may inhibit its use in assessing the effectiveness and efficiency of different regulatory settings. Firstly, DNSPs have different:

- Input costs (e.g. labour rates and local taxes);
- Operating environments (e.g. weather, topography, soil properties, population densities and the urban / rural nature of certain areas);
- Network sizes. For example, Ergon Energy's network area covers more than one million square kilometres, which is over six times the size of Victoria. This network characteristic would impact on our performance against reliability standard targets due to accessibility issues and distance to travel to faults;
- Network types. For example, Ergon Energy has a large sub-transmission system as well as Single Wire Earth Return systems (SWER);
- Reliability targets;
- Asset characteristics (e.g. long, old, radial and sparsely populated distribution and sub-transmission lines);
- Customer bases (e.g. a larger percentage of industrial customers, such as mines, would impact on load and forecasting as they consume large amounts of energy despite representing only a small percentage of total customers);
- Procurement policies (i.e. purchase versus lease policies for property, fleet and IT etc. would affect the mix of capital expenditure (capex) and operating expenditure (opex)); and
- Historical jurisdictional requirements (e.g. capitalisation, cost allocation and accounting practices).

The small number of DNSPs operating within the NEM and the varying benchmarking methods are also problematic. For the former, this makes meaningful statistical analysis difficult while the latter will result in the chosen model being open to criticism as different methods may produce very different results.

[1] p8 of the Issues Paper. Also, the term 'regulatory control period' is defined in Chapter 10 of the Rules.
[2] p21.

Finally, a lack of consistent, high quality data hinders the use of benchmarking. The AER acknowledged this during the 2010–15 Queensland Distribution Determination process:

> *"The AER does not yet have access to the depth of data required to perform detailed benchmarking analysis that will normalise firms to make them directly comparable. The AER considers that it will need data that is reported in a standardised and comparable format to be able to undertake meaningful benchmarking".*[3]

The Australian Energy Market Commission (AEMC), in its Final Report on the Total Factor Productivity Review, also stated that a key reason behind the AER's limited use of benchmarking in its regulatory determinations has been the "lack of consistent data needed to apply benchmarking techniques".[4] The AEMC recommended that a better, more consistent dataset will facilitate greater use of benchmarking in future determinations.

Until the AER has access to sufficient data, it will be unable to employ a greater use of benchmarking to assist with setting or amending capex and opex allowances. This means benchmarking results should continue to be used alongside a range of other evidence, rather than provide a definitive basis for comparison across network service providers (NSPs). It may be that a better approach to the use of benchmarking is to use it as a tool in examining a single NSP's performance over time rather than for comparing NSPs in the same period. Under this approach, a history of data and any changes to the definitions needs to be maintained over time to adequately account for structural breaks in the data. Most NSPs and regulators would need to invest heavily in systems and processes to be able to establish such data sets and it will take years to build a sufficient history. We also suggest that care needs to be taken when interpreting the efficiency of NSPs since the chosen benchmarking methodology is unlikely to completely account for all of the factors identified above.

2.2.2 AER Networks Information Strategy

Ergon Energy understands that the AER is currently reviewing the benchmarking work of other regulatory agencies to develop effective benchmarking techniques as part of its Networks Information Strategy.[5] This will culminate in the development of models to compare the relative efficiency and service delivery performance of DNSPs (taking into account individual circumstances, where appropriate) and assist the AER in its review of DNSP's regulatory proposals. The AER is also gathering information from a range of sources, including via annual Regulatory Information Notices (RIN), to feed into these models. While Ergon Energy recognises that this will enable the AER to use benchmarking to a greater degree in its regulatory determinations, we believe that benchmarking should not replace the AER's detailed investigation of a DNSP's costs provided for in its regulatory proposal.

2.3 Recovering Efficient Costs

Under section 7A(2) of the National Electricity Law, a DNSP must be able to "recover at least the efficient costs the operator incurs in (a) providing direct control network services, and (b) complying with a regulatory obligation or requirement or making a regulatory payment". Ergon Energy is concerned that the use of benchmarking may impact on a DNSP's ability to recover these costs, effectively discouraging investment. That is, benchmarking implicitly implies that high unit costs are the result of inefficiency. This will mean DNSPs are placed in a position where they are required to identify the specific factors that lead to their deviation from the target / frontier, even if costs are efficient. This would be overly burdensome for DNSPs as it will require a DNSP to identify ways in which it differs from other NSPs (i.e. it requires detailed knowledge of other NSPs in the dataset).

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[3] AER (2010), *Final Decision: Queensland Distribution Determination 2010–11 to 2014–15*, May 2010, Appendix G, p424.
[4] AEMC (2011), *Final Report: Review into the use of total factor productivity for the determination of prices and revenues*, 30 June 2011, pii.
[5] Refer to http://www.aer.gov.au/content/index.phtml/itemId/746816.

3. TABLE OF DETAILED COMMENTS

Question(s)	Ergon Energy Response
Scope of the Inquiry	
Given the various ongoing reviews and the consultations associated with them, how can the Commission best add value? Do these reviews have the same broad objective as the Commission or are they more narrowly focused?	Ergon Energy suggests that the Productivity Commission align its work with the various ongoing reviews and consult with stakeholders once those issues are finalised. Ergon Energy believes duplicating consultation will be administratively burdensome for stakeholders and yield little value. It is not clear to Ergon Energy what the Productivity Commission's broad objective is. The Issues Paper identifies that the overarching objective "…is to maximise the long-run benefits to the community as a whole".[6] Meanwhile, the terms of reference state the Productivity Commission is "…to assess the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure to meet the long-term interests of consumers, consistent with the NEO (National Electricity Objective)".[7] The NEO aims to: *"…promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—* *(a) price, quality, safety, reliability and security of supply of electricity; and* *(b) the reliability, safety and security of the national electricity system."* [8] These two objectives are different. The NEO references the "long term interests of consumers" which relates only to the consumption of regulated services. That is, it excludes benefits and costs that accrue to other parties, including businesses, taxpayers and the wider community. The Productivity Commission objective is broader as it relates to the "community as a whole". If the Productivity Commission's objective is to meet the NEO, then the reviews identified in the Issues Paper are consistent with this objective. This is because both the AEMC[9] and the AER[10] must have regard to the NEO when performing or exercising their functions / powers under the National Electricity Law.

[6] p6.
[7] Issues Paper, piii.
[8] Section 7 of the National Electricity Law.

Regulation of the National Electricity Market	
Are there any other major regulations or policies that affect the electricity market that need to be considered when undertaking benchmarking or in understanding any of the possible obstacles to investment in interconnectors?	Ergon Energy agrees with the major regulations and policies set out in the Issues Paper. However, we believe the Issues Paper confuses the role of governments and jurisdictional regulators. For example, page 9 of the Issues Paper states that "(g)overnments regulate networks to ensure the reliability of supply". In Queensland, the Queensland Competition Authority (QCA), as an independent Statutory Authority, reviews the Minimum Service Standards (MSS) that will apply to Queensland DNSPs.
Partial Indicators	
What are the best (and worst) aggregate measures of performance, and why is this so? In which contexts (Australia and elsewhere) have these been most credibly been used?	Please refer to the ENA's submission.
What partial indicators are meaningful? Are there particular parts of network businesses that are easier to benchmark? What are these, why is it easier, and what have benchmarking studies revealed?	Please refer to the ENA's submission. Ergon Energy notes that any assessment of benchmarking techniques or changes to benchmarking approaches should be done in consultation with NSPs.
Are there criteria beyond those identified in box 1 that are useful for discriminating between good and bad benchmarking tools and approaches?	Ergon Energy concurs with the criteria identified in Box 1, particularly with respect to ensuring a benchmark is robust and transparent, and limits onerous data obligations. We also suggest that a benchmark should: • Be consistent with the wider regulatory framework; • Be able to adapt over time and remain fit for purpose; and • Be mindful of resource costs (i.e. the chosen approach should not impose significant additional costs on the AER or NSPs).
What are the weaknesses and advantages of full versus partial measures for benchmarking?	Ergon Energy suggests that the Productivity Commission undertake a detailed analysis to gain a better understanding of these factors. We note that benchmarking total capex over short periods of time can be difficult as the lumpiness of capex programs can impact

[9] Section 32 of the National Electricity Law. Also see section 88 which states the AEMC may only make a Rule if it is satisfied the Rule will or is likely to contribute to the achievement of NEO.
[10] Section 16(1)(a) of the National Electricity Law.

	results. Firm-specific factors that are unaccounted for in a model may appear as inefficiencies, even when this is not the case. On the other hand, partial measures fail to account for the relationships among different factors.
What methods should be used for benchmarking (indexes, corrected ordinary least squares, data envelopment analysis, simple ratios), and what are their strengths and weaknesses?	Ergon Energy considers that benchmarking should not be confined to a particular technique. Rather, the AER should use a range of benchmarking techniques to examine the consistency of results and the robustness of the rank orders. Benchmarking models must allow for adjustment of factors outside the control of NSPs. Accordingly, we suggest that the ISSR Framework developed by BoozAllenHamilton be taken into consideration. The ISSR Framework categorises costs as follows: • Inherent – those costs borne by an organisation due to some third party or environmental influence that cannot be removed (e.g. topography); • Structural – those costs resulting from a socio-economic influence or a legacy of historical events; • Systemic – costs that arise due to a business' own policies and procedures; and • Realised – costs that are borne due to a business' work and labour force management practices. Inherent and structural costs are generally beyond the control of the DNSP and should be accounted for in any benchmarking model. There is a large volume of academic literature on benchmarking techniques, including their strengths and weaknesses and examples of practical applications. Ergon Energy suggests that the Productivity Commission undertake a comprehensive literature review as part of its Inquiry to systematically examine the practical problems with different approaches with respect to regulatory benchmarking. At a high level, Haney & Pollitt (2009) suggest that frontier-based benchmarking techniques are more appropriate during the early stages of regulatory reform; where the focus is on reducing the gap among network businesses.[11] However, frontier-based techniques also require a relatively large sample size,[12] which may be an issue in the Australian context given the relatively small number of NSPs. Average benchmarking techniques are likely to be more suitable once firms have relatively similar costs.[13]
Using Benchmarking to Assess Regulatory Performance	

[11] Brophy Haney, A. & Pollitt, M. (2009), *Efficiency Analysis of Energy Networks: An International Survey of Regulators*, Electricity Policy Research Group Working Paper 0915, October 2009.
[12] Jamasb, T. & Pollitt, M. (2001), *Benchmarking and regulation: international electricity experience*, Utilities Policy 9 (3), pp107–130.
[13] Ibid 11.

Could benchmarking be used to assess the effectiveness and efficiency of different regulatory settings (such as reliability standards)?	Please refer to our comments under Section 2.2 above.
Are there examples where regulatory benchmarking has been used in electricity networks in Australia or overseas?	The AER is required to consider benchmarking information in making regulatory determinations for DNSPs. In coming to its conclusions on Ergon Energy's forecast capex and opex allowances for the 2010–15 regulatory control period, the AER had regard to benchmark capex and opex expenditure that would be incurred by an efficient DNSP.[14] The AER used capex ratio analysis and reviewed unit cost information to assess capex, and used opex ratio analysis and regression analysis to assess opex. Regulatory benchmarking has been used in numerous electricity networks overseas (e.g. Ofgem in the United Kingdom and the DTe in the Netherlands). Ergon Energy recommends that the Productivity Commission undertake a comprehensive review of these approaches.
Are there any other broad benchmarking approaches not discussed above, and where and how have these been used?	Ergon Energy concurs with the benchmarking approaches and methodologies outlined in the Issues Paper. We are not aware of any additional broad benchmarking approaches. We note that many benchmarking studies have focused on frontier-based (e.g. corrected ordinary least square, stochastic frontier analysis and data envelopment analysis) and average benchmarking approaches (e.g. ordinary least square and total factor productivity).
Usefulness of Benchmarking	
Is there a big enough problem to justify new approaches to benchmarking and to incorporate it into regulatory incentive arrangements? To what degree could perceptions of inefficiency reflect the newness of the current regulatory regime or a failure to sufficiently adjust for the differing starting points of different distribution businesses?	Since the current regulatory regime has only been in place for three years, Ergon Energy does not support significant changes to the fundamental design of the regulatory framework, including new approaches to benchmarking, at this time. The AER has commenced collating an enormous amount of data from NPSs through annual RINs and this will need to continue for several years before any meaningful analysis can be undertaken. After which it may then be appropriate to examine what changes may need to be incorporated into regulatory incentive arrangements.
How do existing network suppliers assess the efficiency and performance of their own businesses and how do they use these results?	Over recent years, Ergon Energy has carried out various benchmarking exercises, including:

[14] For further detail, refer to AER (2010), *Final Decision: Queensland Distribution Determination 2010–11 to 2014–15*, May 2010, Appendix G.

Could these results have relevance to regulatory benchmarking, and if not, why not?	• Benchmarking our opex and IT costs against industry peers for our 2010–15 regulatory proposal to the AER; • A benchmarking study of our fleet conducted by UMS Group; and • Carrying out "Value to Customer" surveys to assess our performance with peers across the customer dimensions of electricity supply, customer interaction experience, corporate social responsibility and cost/affordability. Ergon Energy is currently participating in a study that will provide benchmark and cost driver analysis of capex and opex for both system and non-system activities of participant DNSPs.
How should benchmarking be used by the regulator? For example, to what degree could and should it be used as 'high-powered' incentive regulation; as a basis for determining the weighted average cost of capital and efficient spending; or as public information to provide moral suasion for efficiency?	Ergon Energy believes that benchmarking techniques are not robust enough to replace a detailed investigation of costs and should not be relied on entirely to set revenue allowances. Instead, benchmarking should be one of many assessment techniques adopted by the AER to determine efficient and prudent expenditure. We support the use of benchmarking in calculating the Weighted Average Cost of Capital (WACC), but note that the current Rule change process is presently examining this issue.
What is the magnitude of the benefits from using benchmarking in regulatory decision-making in terms of lower unit costs or other performance measures?	Nil comment.
What are the lessons from overseas about their benchmarking approaches, and what aspects should Australia copy or avoid?	Nil comment.
To what degree could the AER use international benchmarking?	Ergon Energy does not believe that the AER should use international benchmarking in its regulatory determinations as this introduces another level of uncertainty. While international benchmarking can produce more sizeable datasets, there is a lack of standardisation across countries, particularly with regard to: • Legislative frameworks (e.g. employment, tax and safety laws); • Regulatory arrangements (e.g. data collection processes, incentive frameworks and reliability standards); • Cost of capital and other financing arrangements; • Exchange rates;

	• Topography; and • Socio-political and socio-economic differences.[15]
How can a good benchmarking model be identified since data and methods always have some imperfections?	A good benchmarking model can be identified through extensive consultation with key stakeholders.
Is there value in 'rough and ready' benchmarking models and how would these be used?	Ergon Energy considers that benchmarking models should be adapted to the Australian context and require careful consideration by all stakeholders prior to their implementation.
What are the most important control factors for benchmarking network businesses (for example, lot frontage, asset vintage, topography, weather variations, customer types, reliability standards, ratio of peak to average demand, and any strategic behaviour by generators and retailers)? What matters less?	Ergon Energy considers that the following control factors are the most important when undertaking benchmarking: • Network scale; • Reliability standards; • Load density; • Load factors arising from customer base; and • Geography (e.g. weather variations and nature of vegetation). Other factors which should be considered include: • Capitalisation, cost allocations and accounting practices; • Input costs; and • Internal policies and procedures (e.g. inspection cycles for preventative maintenance).
What are the main differences in the potential for, and methods of, benchmarking transmission versus distribution businesses?	Given the small number of NSPs in the NEM, Ergon Energy sees value in relying on similar benchmarking methods for both Transmission Network Service Providers (TNSPs) and DNSPs to allow for greater comparison. However, we suggest that these models take account of the differences between transmission and distribution networks such as varying operating environments, reliability standards, and technical specifications.
Should benchmarking results and methodology be publicly available, and if not, why not?	Ergon Energy agrees that benchmarking results and methodology should be made publicly available at some stage in the future in order to promote transparency and participation in the benchmarking process (subject to the need to withhold legitimate

[15] The first four dot points were identified in Frontier Economics (2010), *RPI-X@20: The future role of benchmarking in regulatory reviews*, A final report prepared for Ofgem, May 2010, p20.

	confidential information). This information could be made available during the regulatory determination process and / or published by the AER in its Performance Reports of DNSPs. However, these publications should quite clearly state that care needs to be taken in comparing DNSPs' reported performance information due to varying operating environments etc.
What are the consequences of errors in benchmarking? To what extent do these costs vary for positive versus negative errors? How could the costs of any errors be reduced?	Errors in benchmarking can impact on a NSP's ability to recover its efficient costs and may lead to underinvestment in key network infrastructure which will need to be recovered in a later regulatory control period. Alternatively, it may result in overinvestment and increased electricity prices. Errors, and their resultant costs, can be reduced by establishing robust benchmarking techniques from the outset and using standardised and accurate data.
To what extent would it be helpful to give the AER some discretion in deciding how much weight should be given to benchmarking and other tools when making regulatory determinations?	The AER already has discretion in deciding how much weight should be given to benchmarking and other tools when making regulatory determinations. Under the Rules, the AER must have regard to the opex and capex factors when assessing a DNSP's forecasts. These factors include information provided in the regulatory proposal and benchmark expenditure incurred by an efficient DNSP. The Rules do not prescribe specific weightings to the AER's consideration of these factors.
What if any, alternative policies may be superior to benchmarking? What, if any, policies could complement the use of benchmarking?	Nil comment.
Rival Explanations	
What are the principal reasons for the apparent decline in the productivity of the electricity networks and for the associated increases in electricity prices? In particular, what have been the effects of rising input prices, past underinvestment, building ahead of use, rising peak demand, underground cabling and requirements for reliability requirements? To what extent have investment responses to the above factors been economically efficient?	Ergon Energy is concerned by the Productivity Commission's over-simplification of the reasons for increases in electricity prices and its attribution to the apparent decline in productivity. Rising electricity prices are driven by: • Increased investment to replace ageing assets and to meet increased peak demand; • Growing customer connections; • Higher reliability standards; • Increases in labour and material costs; • Higher cost of capital due to the global financial crisis;

	• Commonwealth and state-based renewable energy policies such as the Small-scale Renewable Energy Scheme and feed-in tariff arrangements; and • Safety net tariffs. Ergon Energy refers the Productivity Commission to the ENA's submission to the AEMC's Directions Paper on network regulation for further detail on this issue. Ergon Energy notes that costs associated with electricity networks are not the sole driver of changes in retail electricity prices. As such, Ergon Energy urges caution in using retail electricity prices as the basis for any analysis. For example, in Queensland, the methodology for increasing retail electricity prices changed in 2007 from a CPI basis to a Benchmark Retail Cost Index which used changes in costs (generation, network and retail) between two years to adjust retail tariffs. Therefore, if the Productivity Commission continues to refer to retail electricity tariffs, it should analyse and understand the methodology for calculating those tariffs and how that relates to underlying cost changes.
To what extent have rising network costs reflected failures to correctly define project scope, to adequately control project costs and 'gold plating'?	Ergon Energy does not believe rising network costs reflect failures to correctly define project scope, to adequately control project costs and 'gold plating'. Ergon Energy's expenditure for the 2010–15 regulatory control period as determined by the AER is set to be efficient and prudent. The AER, in its Final Distribution Determination for Ergon Energy, rejected both the total capex forecasts and total opex forecasts proposed in our regulatory proposal. The AER then substituted its own forecast of total capex (opex) it considered reasonably reflected the capex (opex) expenditure criteria, having regard to the capex (opex) factors outlined in the Rules.[16] This led to a 17 per cent reduction in Ergon Energy's capex allowance, and a 10 per cent reduction in opex allowance.
If there has been gold plating by network businesses, how has this been realised (premature investment, over-specification of network elements, excessive reduction in service interruption risks)?	As discussed above, Ergon Energy does not believe NSPs have engaged in 'gold plating'.
What is the evidence about the comparative roles of the above factors?	Nil comment.
To what extent have Garnaut, Mountain and Littlechild identified	Garnaut and Mountain use real capex per connection to illustrate the inefficiency of

[16] See clauses 6.5.6(e) for opex and 6.5.7(e) for capex.

genuine inefficiency in electricity networks?	government-owned DNSPs compared to privately owned DNSPs. This fails to acknowledge the various differences between network businesses, such as population density, reliability standards, the legacy of previous regulators and the impact of dampened price signals where retail tariffs are regulated. As such, Ergon Energy does not believe these papers have identified genuine inefficiencies. Ergon Energy refers the Productivity Commission to the ENA's submission on this issue.
The interaction of benchmarking with the regulatory framework	
Do the current Rules limit the use of benchmarking? If so, how do they do so, to what extent, and what would be the appropriate remedy?	Ergon Energy does not believe the current Rules limit the use of benchmarking. The existing framework allows the AER to assess expenditure forecasts and make adjustments as appropriate in order to ensure prudent and efficient expenditure. In making this assessment, the AER may have regard to a range of factors, including benchmarking, and is not limited to what is contained in the regulatory proposal.[17] The debt risk premium, used in the calculation of the WACC, is also based on a benchmark corporate bond rate.[18] In practice, the AER has adopted benchmarking in several of its determinations for the DNSPs. The only limitations the AER has faced are the lack of available information and methodological issues, not restrictions in the Rules. The AER has already moved to address the issue of available information (annual RINs for each NSP) and has already developed and is developing models (REOPEX in Victorian Decisions) to use the data in future Distribution Determinations.
In particular, do the Rules restrict the weight that the AER can apply to benchmarking analysis compared with the information that distribution business make available in the building blocks proposals? For example, could the AER reject the evidence from the building blocks analysis if it found compelling alternative evidence of lower required spending from benchmarking?	Ergon Energy does not believe the Rules restrict the weight the AER can apply to benchmarking analysis compared to the information made available in the regulatory proposal. This issue was examined by the Australian Competition Tribunal (the Tribunal) in the *EnergyAustralia and Others* matter.[19] The Tribunal found that the AER is permitted to reject a DNSP's entire methodological approach and adopt some other approach. The Tribunal stated: *"The primary discretion given to the AER by cl 6.12.3(a) is to refuse to*

[17] Clause 6.5.6(e)(4) of the Rules requires the AER to take into account the "benchmarking operating expenditure that would be incurred by an efficient DNSP" when determining whether to accept a forecast proposed by the DNSP. Similarly, clause 6.5.7(e)(4) permits the use of benchmarking for capex.

[18] Clause 6.5.2(e) states "the debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency".

[19] Application by EnergyAustralia and Others, (2009), ACompT 8, 12 November 2009, Accessed 27 March 2012, http://www.austlii.edu.au/au/cases/cth/ACompT/recent.html.

	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 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. Once the basis of EA's [EnergyAustralia] approach to the assessment of maintenance costs is rejected as above, then the approach undertaken by the AER is an appropriate way to proceed."
Must the AER forensically examine each aspect of the building blocks approach even if it believes that a more simple and robust benchmarking approach were available?	Ergon Energy considers that the AER must be required to start from the regulatory proposal and make minimal adjustments to ensure prudent and efficient expenditure. A line-by-line assessment of the NSP's proposal is not necessary, and in fact the AER have made adjustments to capex and opex without undertaking a line by line assessment.
Are there any other limitations faced by the Australian Energy Regulator in using benchmarking, such as the merit review process?	Other than methodological issues and the lack of available information, Ergon Energy does not believe there are any other limitations faced by the AER in using benchmarking. In particular, we do not consider the merit review process to be a limitation. Rather, it is necessary to negate the regulatory risks that arise during the determination process. For benchmarking, this may include the subjectiveness of the technique chosen or unjustifiably interpreting the residual as 'inefficient'. These decisions have long-term impacts on investments and a NSP's commercial rights so it is critical that the accountability of merits review access be present. It should be noted that a DNSP can only access merits review when it believes: • The AER made an error of fact in its findings of facts, and that error of fact was material to the making of the decision; • The AER made more than one error of fact in its findings of facts, and that those errors of fact, in combination, were material to the making of the decision; • The exercise of the AER's discretion was incorrect, having regard to all the circumstances; and • The AER's decision was unreasonable, having regard to all the circumstances.
What restrictions, if any, should apply to the AER's use of benchmarking or other analytical tools?	Please refer to our earlier comments in relation to the AER's use of benchmarking.
Should the AER select the best performer as the benchmark, or choose a benchmark close to, but not at the frontier?	Ergon Energy is concerned by the wording of this question as it implicitly implies that a frontier-based approach will be adopted by the AER. As discussed above, Ergon Energy

What criteria could be used to determine the threshold between unreasonable and reasonable costs?	considers that the benchmarking model(s) should be chosen after careful consideration and consultation with stakeholders. Having said this, Ergon Energy is supportive of choosing a benchmark close to the frontier since the frontier may not be a valid comparator (e.g. due to data errors, or shocks or differences between NSPs which have not been captured by the model).
In cases where the AER's benchmarking findings cast doubt on building block proposals but do not provide an exact alternative, should there be scope for the AER to negotiate a settlement with network businesses? How would that be achieved?	If the benchmarking findings cast doubt on building block proposals but do not provide an exact alternative, the AER should adopt other assessment tools. As noted previously, benchmarking should be one of many assessment tools used by the AER in assessing DNSPs' regulatory proposals.
Could benchmarking reduce prescriptive regulation in the Rules? How? Which ones?	Ergon Energy believes the Rules, as currently drafted, strike an appropriate balance between prescription and discretion.
How would a regulator use benchmarking analysis that produced cost estimates significantly different from those from the building blocks approach? What approaches have other countries used in such instances?	Ergon Energy suggests that where benchmarking analysis has produced costs estimates significantly different from those from the building blocks approach, this should prompt further investigation. As indicated above, the Productivity Commission should conduct a comprehensive literature review of approaches in other countries.
Has the AER used benchmarking effectively? Should it adopt different practices? Are there any major process or resource obstacles to the AER's use of benchmarking?	Nil comment.
Is there scope to introduce competition in parts of the electricity network? If so, where and when? Would that reduce any need for benchmarking in those parts? To what extent could performance in competitive segments be used as benchmarks for non-competitive segments?	As part of the Classification of Services, the AER has to, among other things, have regard for the potential for development of competition in the provision of services and how the classification might influence that potential. This informs the decision on the Classification of Services which in turn determines the need for any benchmarking.
Cost of Capital	
To what extent, if any, are there flaws in the AER's current	Ergon Energy considers that the definition of the debt risk premium (DRP) in the Rules,

benchmarking of the WACC, and if so, how could it be improved?	and the AER's interpretation of clause 6.5.2(e), is too narrow. These two factors have led to the AER relying on a very limited range of data and raising concerns that the DRP is not cost reflective. As highlighted in our submission to the AEMC's Consultation Paper,[20] we support consideration of whether a less prescriptive definition for the DRP is appropriate to allow the AER to draw upon a sufficient range of data sources. The Rules should provide some guidance as to how the DRP is to be estimated, rather than giving complete discretion to the AER via periodic WACC reviews. Ergon Energy does not support the AER's proposal to increase the scope of the WACC review to allow the AER to determine the methodology of setting the DRP. The AER's proposal for broad regulatory discretion is a significant departure from current practice. Ergon Energy also does not support the AER's implied proposal to set the regulated cost of debt based on the actual funding practices of the NSPs. Calculating the regulated cost of debt according to a longer term moving average may have some merit. However, the risk free interest rate and DRP should correspond to a ten year term. The current method of fixing the regulated cost of debt component of the WACC over a short time interval every five years creates significant market signalling and re-pricing risks for NSPs with large debt portfolios.
Is there evidence that the regulatory WACC should be different for government-owned compared with private network businesses? What implications would differential WACCs have for the eventual privatisation of such businesses?	There is no evidence that the regulatory WACC should be different for government-owned NSPs compared with privately-owned NSPs. In their Directions Paper to the *Economic Regulation of NSPs* Rule change request, the AEMC state: *"The Commission does not consider the EURCC proposal for different arrangements to apply to government-owned and private sector NSPs for determining the cost of debt is appropriate. This is because it fails to fully recognise the role of competitive neutrality principles. In addition, it does not factor in the impact and role of debt neutrality fees. Also, it could remove the option of any future sale or other divestiture of government-owned NSPs".*[21] Ergon Energy supports the AEMC's view on this matter. In addition, Ergon Energy notes that the proposal would give rise to circumstances where NSPs operating in different geographic regions set prices that are differentiated by ownership rather than by reference to the underlying economic costs of providing those services. This is inconsistent with the NEO and could lead to an artificial incentive for over-investment by

[20] Ergon Energy (2011), *Submission on the Economic Regulation of Network Service Providers Consultation Paper*, 8 December 2011, pp3 and 15.
[21] AEMC (2012), *Directions Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 2 March 2012, pvi. For further analysis, refer to pages 114 to 120.

	customers in the lower price regions, along with under-investment in demand side initiatives, undermining the principles of allocative and dynamic efficiency.
What, if any, are the effects of the various WACC determinations on: • the incentives of private versus government-owned network businesses? • choices about spending on capital expenditure versus operating expenditures?	Ergon Energy is committed to maintaining its capex and opex within the allowances set by the AER for the 2010–15 regulatory control period. Capex and opex levels are based on the various programs of work for the business and reflect customer demand.
How can the different patterns between forecast and realised spending between private and government-owned network businesses be explained?	Nil comment.
How does the efficiency of private distribution businesses compare with government-owned ones, and if different why and how would this be remedied?	Nil comment.
Do government-owned network businesses have any non-commercial objectives? How do these vary by business type or jurisdiction? How do they affect the behaviour or efficiency of the businesses? Should they be removed or altered? Should they be factored into benchmarking analysis?	Yes, government-owned network businesses have non-commercial objectives as do privately owned networks. For example, section 40A of the Queensland *Electricity Act 1994* requires DNSPs to offer supply when a customer applies for customer connection services. Ergon Energy is also committed to corporate social responsibility activities such as forming active and mutually beneficial relationships with organisations and communities, and improving energy consumption at Ergon Energy buildings. Non-commercial objectives can promote inefficiencies. However, there are valid social reasons for doing so (e.g. customer protection and providing essential services). Removing or altering these objectives is likely to have a detrimental impact on customers and the community as a whole. Ergon Energy believes that non-commercial objectives should be factored into benchmarking given their impact on NSPs.
While government-owned businesses pay corporate taxes to state governments – consistent with competitive neutrality principles – are those principles undermined by the shareholder status of governments or any other governance issues?	The competitive neutrality principles are not undermined by the shareholder status of government-owned NSPs. As noted by the AEMC's consultants, SFG,[22] the return received as a shareholder should not be compared with the taxation revenues received as the taxing authority. This confuses the two separate roles of the government.

[22] Ibid 21, pp117–118.

Does that affect investment decision-making by government-owned businesses or the determination of reliability standards and other policies by governments?	
If any biases towards excessive investment posed by the WACC and the rollover arrangements of the regulated asset base were removed, would that eliminate the need for further development of benchmarking?	Ergon Energy does not agree that there are excessive investment biases posed by the WACC and the rollover arrangements of the Regulatory Asset Base. The AEMC is currently considering this matter as part of its review of Rule changes proposed by the AER and energy users. This is the appropriate process for addressing these concerns.
Reliability Standards	
To what degree do different jurisdictions' reliability standards affect costs, if at all? Do different standards affect the potential and/or incentives for a single network business to extend its network across borders?	As noted above, reliability standards impact costs in each jurisdiction. However, the differences between jurisdictions do not directly impact costs. Having different standards across jurisdictions can negatively impact on an NSP wishing to extend its network across borders due to the increased difficulty and administrative burden in managing different sets of standards. Ergon Energy has assets in NSW and arrangements need to be agreed between jurisdictions to allow this to work effectively.
Why have reliability standards been increased over time, and what impacts have these increases had on costs?	Reliability standards have generally increased over time as a result of growing customer expectations and the perceived risk of outages. In Queensland, a security of supply standard of N-1 on critical energy supply infrastructure was implemented following the 2004 Electricity Distribution and Service Delivery (EDSD) Review.[23] The EDSD Review concluded that the security of supply of the distribution networks had reduced to an unacceptable level. Ergon Energy has invested significantly in pursuing the N-1 reliability standards arising from the EDSD Review, with further investment expected in the future. Ergon Energy notes that the AEMC is conducting a review of distribution reliability outcomes and standards, as well as the impact that such practices may have on costs and allowed revenues.[24] The review will be undertaken in two workstreams: • A review of the distribution reliability outcomes in NSW; and • A review of the frameworks across the NEM to identify whether there is merit in developing a nationally consistent framework for distribution reliability outcomes.
To what extent would adoption of a probabilistic versus deterministic framework change costs?	Following the EDSD Review, Queensland DNSPs were required to apply a deterministic methodology, through their specific N-1 standards. The Panel chose this approach as it

[23] A system designed to N-1 standard would maintain supply with one key network element out of service.
[24] Refer to http://www.aemc.gov.au/Market-Reviews/Open/review-of-distribution-reliability-outcomes-and-standards.html.

What risks and benefits would this entail?	copes with all levels of demand. As noted above, this led to significant investments in the network. During the 2011 Electricity Network Capital Program (ENCAP) Review, Ergon Energy proposed a variation to our N-1 criteria, arguing that the deterministic N-1 standard does not balance the cost of compliance with the benefits realised. We proposed that a cost-benefit methodology should apply to some loads. This approach would compare the value to the community of duplicating assets versus the cost of duplication, and take into account factors such as the duration of peak loads and the availability of mobile options. The Panel supported our proposal, provided that a decision to not proceed with augmentation is documented in our Network Management Plan. Ergon Energy expects this will reduce the costs involved in meeting reliability standards.
What evidence is there of customer involvement (such as willingness to pay) in setting reliability standards?	Clause 6.6.2(b)(3)(vi) of the Rules requires the AER to take into account the willingness of the customer or end user to pay for improved performance in the delivery of services when developing and implementing the Service Target Performance Incentive Scheme (STPIS). The incentive rates for the STPIS are calculated using the Value of Customer Reliability values determined for VENCorp, the Victorian Energy Networks Corporation.[25] As such, they may not necessarily be an accurate representation of Queensland customers' willingness to pay. A customer's willingness to pay is taken into account when reviewing and setting the MSS arrangements for Queensland distributors.[26] Similar to the STPIS arrangements, this information was gathered from studies conducted interstate and may not necessarily be relevant in Queensland. It is understood that the QCA plans to consider this issue further prior to the next review. Ergon Energy supports this position.
How are existing reliability incentive schemes functioning and how could benchmarking contribute to their design?	Ergon Energy currently has ± 2 per cent of its annual revenue at risk under the STPIS arrangements governed by the AER. Ergon Energy's STPIS is based on Reliability of Supply (RoS) and Customer Service components, with the RoS having greater weighting. Benchmarking of reliability incentive schemes could be economically counter-productive to both DNSPs and their customers if it is not based on 'like for like' comparisons. DNSPs with a lower customer density and predominantly radial / rural network topography could be forced to invest an unreasonable amount of money to upgrade or

[25] AER (2009), *Final Decision: Electricity distribution network service providers Service target performance incentive scheme*, May 2009.
[26] Refer to http://www.qca.org.au/electricity/service-quality/RevMinServStandLev.php.

	build their network to meet the performance targets that are not comparable to their existing network structure. Customers who get supplied from a less reliable radial chain could be forced to pay the same price as the customers supplied from a more reliable urban / meshed network.
What is an appropriate governance structure for setting and monitoring reliability standards, and what is the rationale or evidence base for different standards across jurisdictions?	Ergon Energy considers that reliability standards should be set and monitored by a regulator. Under the current legislative and regulatory requirements, Ergon Energy must comply with the: • MSS set by the QCA. The MSS are annual reliability performance expectations which relate to both planned and unplanned outages. Ergon Energy is accountable for delivering the MSS as a condition of maintaining its Distribution Authority (license); and • STPIS set by the AER from 1 July 2010. The STPIS relates to unplanned outages, including service fuse and beyond outages for individual customers (which are currently excluded from the MSS). As noted above, the STPIS provides Ergon Energy with financial incentives to improve reliability of supply and penalises Ergon Energy if the STPIS targets are not met. Given the introduction of the STPIS, Ergon Energy recommended to the Panel of the ENCAP Review that the MSS be repealed. The Panel concluded the financial incentives under STPIS do not guarantee acceptable reliability levels for customers and the MSS should continue.[27] There are numerous reasons for different reliability standards across jurisdictions. These include: • Geographically diverse networks with distinct weather influences; • Different network topographies; • Customer density; and • Customers' willingness to pay.
To what degree should a jurisdiction that specifies a higher reliability standard than others justify such a requirement to its	Ergon Energy supports a process that promotes transparency and believes that reliability standards should be based on a cost-benefit analysis that incorporates customers'

[27] Independent Panel (2011), *Electricity Network Capital Program Review 2011: Detail report of the independent panel*, Accessed 21 March 2012, http://www.business.qld.gov.au/energy/electricity-queensland/review-electricity-distributors.html, p46.

constituents based on a transparent cost-benefit analysis?	willingness to pay and customer needs. It should also take into consideration an NSP's ability to meet the higher standard.
Demand Side Management	
What role could demand management play in reducing peak demand, how would it work, how much would it cost, and what network savings would be experienced? In which parts of the network are cost savings most likely and why?	Demand management can play a significant role in reducing peak demand and, hence, peak demand driven infrastructure investments. The costs and savings will vary across locations, networks and jurisdictions. Ergon Energy believes that broad-based studies claiming levels of national savings need to be viewed with caution. Ergon Energy considers that cost savings are more likely to occur in areas of the network where there are impending constraints or potential breaches in security criteria.
What are the regulatory and other obstacles to demand management or other approaches that give consumers choice? How are these changing?	Ergon Energy considers the following to be regulatory obstacles to demand management / demand-side participation: • Ring-Fencing requirements. Under the AER's Ring-Fencing Guidelines for Queensland, DNSPs are generally not able to own generation assets within the regulated business. This means that embedded generation is not used as much as it could be. Further, ring-fencing of information between retailers and DNSPs can make using embedded generation difficult when it comes to understanding the best operational solutions for distributed generation; • Innovation incentives. Current legislative requirements need to be reviewed to provide greater incentive to invest or participate in trial and pilot studies, and deploy demand management options. These costs may need to be factored into the Distribution Determination process (i.e. costs may be higher than the current Demand Management Incentive Allowance); and • Regulatory Tests. Demand management options can be preparatory work to a distribution investment but the need to conduct a Regulatory Test well in advance makes these solutions less attractive. With respect to other obstacles, demand-side options have a higher level of uncertainty and carry a greater risk than traditional network solutions, particularly in relation to reliability, commercial and technology risk. Outcomes from the AEMC's current review of demand-side participation, *Power of Choice - giving consumers options in the way they use electricity*,[28] and the *Distribution*

[28] Refer to http://www.aemc.gov.au/Market-Reviews/Open/stage-3-demand-side-participation-review-facilitating-consumer-choices-and-energy-efficiency.html.

	Network Planning and Expansion Framework Rule change request,[29] may alleviate some of these concerns.
How do network providers model and make financial decisions about the impact of peak demand growth on network adequacy, including identification of the most cost-effective network investment solution (for a given reliability standard)?	Ergon Energy examines the Net Present Value (NPV) of the various options. The assessment of demand management options includes the value of capital deferral, if applicable. Otherwise, the costs are compared against benchmark costs that are calculated for our network and segmented geographically. Ergon Energy is also working with ClimateWorks Australia, a non-profit collaboration hosted by Monash University in partnership with The Myer Foundation, on the development of cost curves for various demand management initiatives.
How could benchmarking or other tools identify the degree to which network businesses have efficiently used demand-side management as substitutes for building redundancy in their networks?	Ergon Energy considers that it would be difficult to measure the degree to which NSPs have "efficiently used" demand management. Potentially, this could be achieved by comparing load forecasts without demand management to those with the implemented demand management programs. However, Ergon Energy considers that this is fraught with risk considering the differences in locations and their particular needs.
What is the evidence about the effectiveness and customer acceptance of demand management provided by the various trials and experiments in Australia and internationally? What factors have inhibited the use of already installed smart meters?	Ergon Energy has extensive evidence from trials and programs in relation to the effectiveness and take-up of demand management options. Customer acceptance continues to be a challenge as demand management needs to be provided on the basis of a value proposition for the customer, while it is too often considered as a value proposition for the network. Ergon Energy therefore considers that the success of demand-side participation interventions will rely strongly on options that do not require significant variation in customer practices or considerable upfront capital investments. Ergon Energy believes poor consumer engagement by the industry and government has inhibited the use of already installed smart meters (i.e. the value proposition for customers has not been communicated appropriately). For example, displaying the meter charge as a separate charge on customer bills in Victoria has created issues as customers have seen their costs increase with no perceivable benefit. Further, there has been negative publicity regarding the safety of smart meters (e.g. radiofrequency emissions and 'exploding' devices).
Interconnector issues	
To what degree are interconnectors important to greater competition and greater efficiency in the NEM (once account is taken of the costs of construction and any collateral investments	Nil comment.

[29] Refer to http://www.aemc.gov.au/Electricity/Rule-changes/Open/distribution-network-planning-and-expansion-framework.html.

required)?	
What is the magnitude of the impacts on prices, generator capacity and the use of renewable power arising from any deficiencies in interconnector investment? In effect, do any flaws matter much?	Nil comment.
What empirical methods could be used to indicate the scope for further interconnectors?	Nil comment.
What are the obstacles to efficient interconnector investment and how could these be overcome?	Nil comment.
Are current coordination and planning arrangements efficient?	Nil comment.
If more interconnection is efficient, how much and where would the additional capacity be built?	Nil comment.
Why should regulations for transmission and distribution investment be different?	Ergon Energy believes there are a number of key differences that exist between Transmission Network Service Providers and DNSPs that influence variations in regulations for transmission and distribution investment. These differences are largely reflective of sector-specific issues (e.g. technical requirements), variations in operating environments and the content of jurisdictional regulatory regimes (e.g. reliability standards). For example, regulations for distribution investments need to consider: • The more localised function of distribution networks; • The larger volume of investments undertaken by DNSPs; and • The sensitivity of distribution to decisions made by smaller groups of customers.
What are the advantages and disadvantages associated with various options to improve interconnector efficiency, taking into account that some potential solutions (such as public contest methods) may have far-reaching impacts on other parts of the market? What changes in distribution and transmission regulation would be required to permit more market-based interconnector arrangements?	Nil comment.
To what extent is it likely that prospective upgrades in	Nil comment.

interconnection capacity will resolve the currently perceived problems without a need for policy changes? Are longer-term policy changes required to ensure longer-term upgrades?	
Will the value of greater interconnector capacity rise as carbon pricing creates larger cost margins between competing generators located in different states? If so, to what extent?	Nil comment.
Given the AEMC's ongoing review of the transmission framework, where can the Commission add the most value to interconnector policy issues?	Nil comment.
What are the lessons from other countries' approaches to interconnector investment, including the Argentinian approaches and the new cost allocation principles of the United States Federal Energy Regulatory Commission (Order 1000) released in July 2011?	Nil comment.
Taking account of the costs of interconnectors and their transmission losses, to what extent could congestion and price separation events be better addressed by alternatives, such as more investment in transporting gas to gas-fired generators, or by using distributed generation? Are there barriers to such alternatives?	Nil comment.
The Role of Generators	
To what degree does the type, location and conduct of generators affect the efficiency of the electricity network? What are the implications of any such impacts?	The type and location of generators can detrimentally impact on a DNSP's network if it is not managed appropriately. The current networks were not designed with the concept of two-way flows in mind. Consequently, in a number of situations, the implementation of generation causes additional network investment, not less.
How would benchmarking of network businesses, or its application in regulations, take into account any such complexities?	Ergon Energy does not believe it is beneficial for benchmarking to take into account these complexities.
Accounting for the Future	
What are trends in electricity supply and how will these affect	The introduction of carbon pricing and the advent of rapidly changing technologies are

regulation, and the need for, and use of, benchmarking and other regulations?	likely to see a shift towards low-carbon energy sources. New technologies will also assist customers in managing energy and demand, and lead to the emergence of third party suppliers offering additional services such as advice on managing electricity bills. The regulatory framework will need to adapt to and embrace these changes while ensuring the maintenance of a stable electricity supply system. Considering the current state of benchmarking in Australia, Ergon Energy does not believe that benchmarking could be used to take into account future trends in electricity supply at this stage.
To what extent, if at all, will renewable generation and household feed-in tariffs require network upgrades? How costly and efficient would it be?	Ergon Energy estimates that the impact of solar photovoltaic systems, coupled with the Solar Bonus Scheme, will require an additional $130 million of network upgrades during the current regulatory control period.
Is local small-scale power generation likely to develop cost-effectively to such a degree that it (a) erodes the distribution network natural monopoly (b) significantly reduces network investment requirements? If so, how long before this happens, with what technologies and costs, and with what implications for regulation? Are there obstacles to efficient distributed generation?	The impact of local small-scale power generation will significantly depend on the policies surrounding the implementation of those technologies. However, it is unlikely to erode the distribution network's natural monopoly. Networks will still be required to provide interconnection of the local small-scale generation. If properly applied though, this type of generation has considerable potential to impact future network investments. It is extremely difficult to determine the time period within which this will occur. The take-up of solar photovoltaic systems has been faster than expected due to the incentives provided by government. The perverse outcome is that these incentives have promoted the inefficient use of this technology from a network perspective, causing investment in networks rather than deferring it.
How fast will Australia move towards 'smart grids'? How much will these cost, and what impacts will they have on reliability and overall network investment? Will they provide better evidence about the comparative performance of different network providers?	As with any new technology, there will be significant costs in rolling out smart grids. If implemented correctly, smart grids should improve the customer's energy experience and reduce the need for investment in network infrastructure. Smart grids will provide substantial information about the performance of the network, but they are unlikely to provide evidence about the performance of individual NSPs.
To what degree could the likely future development of better benchmarking tools be incorporated into current incentive regulations to reduce any bias towards excessive investment? How should any such incentive regulations be designed? What are the major advantages and disadvantages of such	Please refer to our earlier comments.

incentive arrangements, and in particular the magnitude of any risks that such an approach could chill efficient investment? Are there any similar arrangements in utilities or other regulations that provide lessons on such incentive arrangements?	
Implementation Issues	
How should policy change be implemented, what are the priorities and how long will it take? Is there a critical sequence of changes that should take place?	Please refer to our general comments below.
Are there significant costs in implementing change?	Please refer to our general comments below.
Which agencies/parties should do what when implementing change?	Please refer to our general comments below.
Is there any interaction with other policies/regulations that would affect the effectiveness of implementation?	Please refer to our general comments below.
Given the experience of the last five to 10 years, over the longer term, how should the NEM be modified to meet the best interests of consumers?	Ergon Energy considers this question to be beyond the scope of the Inquiry.
General comments	Ergon Energy believes that implementation issues should be considered once policy changes are more firmly established. However, we agree that the introduction of any new benchmarking and interconnector approaches will require extensive consultation, incur costs and take time to implement. All parties should be provided with an appropriate period of time to transition to a new regime, and policy changes at a national level will need to be cognisant of jurisdictional requirements.