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24 November 2016

Mr Neil Howes
Australian Energy Market Commission
PO Box A2449
SYDENY SOUTH NSW 1235

Dear Mr Howes

Submission on National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2016

Ergon Energy Corporation Limited (Ergon Energy) welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC), on its consultation on the *National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2016*. The attached submission is provided by Ergon Energy in its capacity as a Distribution Network Service Provider in Queensland.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact either myself on (07) 3851 6416 or Trudy Fraser on (07) 3851 6787.

Yours sincerely,

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Submission on the *National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2016 – Consultation Paper*

24 November 2016

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Australian Energy Market Commission

24 November 2016

This submission, which is available for publication, is made by:

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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 Australian Energy Market Commission (AEMC) on its *National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2016 – Consultation Paper* (Consultation Paper).

Ergon Energy is a member of Energy Networks Australia (ENA), the peak national body for Australia's energy networks. The ENA has prepared a comprehensive response addressing the AEMC's Consultation Paper. Ergon Energy is generally supportive of the responses contained in their submission.

Ergon Energy is not opposed to the general intent of the Consultation Paper, and generally supports the broad proposals contained therein, subject to certain thresholds and clarifications highlighted in this submission.

Ergon Energy acknowledges that the energy environment is constantly evolving and that alternative solutions are continuing to emerge. However, Ergon Energy's experience in applying the Regulatory Investment Test for Distribution (RIT-D) process to-date has failed to yield a viable alternative that provides a credible technical and economical solution for augmentation projects. On this basis, and given the increased complexity of the operational and commercial environment associated with replacement of network assets, particularly lower value, small-scale assets such as poles, cross-arms or circuit-breakers, Ergon Energy believes that extending the RIT process to replacement expenditure will result in an increased regulatory burden that is unlikely to reveal any benefits to market stakeholders and consumers of electricity.

Ergon Energy suggests that alternative approaches to achieving the Australian Energy Regulator's (AER) policy intent of increased transparency and consideration of network asset replacement decisions may be more efficient. For example, Ergon Energy currently engages with the market through a network incentive map which was specifically developed for augmentation projects and is exploring opportunities to create incentive areas based on any network investment to provide an appropriate demand side solution which can mitigate the need for investment. The ENA has also provided alternative solutions in their submission such as innovative, collaborative data provision services provided by the Institute for Sustainable Futures' Networks Opportunity Maps, which will provide longer-term solutions to providing additional forms of access to such asset replacement data and reduce the need for DNSPs to be subject to regulatory requirements. Ergon Energy supports the ENA's position on the appropriateness of these alternative mechanisms and notes that these mechanisms can provide energy market stakeholders and non-network service providers with early information and an avenue for engagement with DNSPs.

Ergon Energy agrees the suggested reporting requirements will achieve increased transparency. However, Ergon Energy cautions that this should only be applied where a net benefit of doing so is apparent and will outweigh any additional administrative burden it will impose. As such, Ergon Energy seeks clarity on the extent to which some of the reporting obligations will apply to individual assets and de-ratings. In particular, Ergon Energy notes the AER's draft Rule 5.14A.1(c)(2) suggests that the AER, in determining whether to include an asset type to be reported on in the reporting guideline, should give consideration to whether a type of network asset is likely to be retired individually or as part of an asset replacement program. Ergon Energy does not support inclusion of asset replacement programs, such as a program of circuit breaker replacements across the distribution network, in the cost threshold due the geographic dispersion and low value of each individual asset component, as well as the operational and technical complexities associated with alternative solutions for these asset types. While Ergon Energy currently provides replacement program information in the Distribution Annual Planning Report (DAPR), the value of the program in its entirety should not provide the basis for detailed reporting and seeking an alternative market solution through the RIT process. Ergon Energy has provided further detail on the appropriateness of reporting and RIT thresholds, and seeks clarity on the threshold intent in our responses to the questions raised in the Consultation Paper in the following section.

In response to the AEMC's invitation to provide comments on the Consultation Paper, Ergon Energy has focused on questions raised in the Consultation Paper. Ergon Energy is available to discuss this submission or provide further detail regarding the issues raised, should the AEMC require.

Table of detailed comments

Consultation Paper Feedback Question	Ergon Energy Comment
Issue 1: The problem	
1. (a) Are non-network solutions a viable alternative to replacing network assets on a like-for-like basis?	Ergon Energy notes that there may be limited circumstances where non-network solutions could provide a commercial and technically viable alternative to replacing network assets, where the asset type, network configuration and timing of replacement are congruent. In our most recent DAPR (2016-17 to 2021-22), Ergon Energy reported the proposed replacement of the Charleville Static VAR Compensator (SVC). The SVC is at its maintenance end-of-life, with spare parts no longer available from the manufacturer, and technical expertise difficult to procure. This creates an increasing reliability and quality of supply risk. A like for like replacement SVC will maintain dynamic stability of the power system by providing reactive power compensation to control network voltages within statutory limits. Ergon Energy is currently exploring alternative energy solutions at the Charleville substation through third party generation arrangements which may impact reactive power compensation requirements. It is possible that such solutions may reduce, increase or have no impact on reactive power requirements at Charleville, depending on the size and time of generation. If the alterative solution adopted fully integrates the function of reactive compensation currently provided by the SVC, then the present need to replace the Charleville SVC may be unnecessary. On the other hand, if the alternative solution does not fully integrate the function of the SVC and a significant amount of real power is injected at the Charleville substation, then there may be a need for increased reactive compensation to accommodate this requirement. In other words, there could well be a need for SVC augmentation if the third party generation adversely impacts network voltages at such sites. Utilising a demand side solution to replace a network asset can increase the complexity of the operational and commercial environment. There are significant technical, commercial and operational constraints that impact not only the network but also any demand side participation that require detailed assessment and consideration. Furthermore, it is extremely unlikely that a non-network solution will offer a viable alternative to network asset replacement on the small scale. The mere cost of going to market for a

	solution at this scale (if a RIT-D were triggered by a program-level threshold as noted in our introduction) is likely to outweigh any benefit of doing so. For example, component replacement of a single pole or cross-arm represents small scale replacement investments that would be less than the cost of performing a RIT-D and not provide any potential market possibilities.
(b) How does this differ from the potential for a non-network solution to provide a viable alternative to augmenting the network?	The decision to replace or refurbish a network asset is driven by the end of life, physical conditions and/or serviceability of each asset. Network assets requiring refurbishment or replacement are typically replaced on a component basis, are likely to be geographically isolated and of low value. Each different component or asset type typically has a different expected life span, which naturally promotes piecemeal replacement strategies. The decision to augment the network is driven by a risk assessment of the network, considering demand growth, load profiles, network topologies, utilisation levels and planning and security criteria. A need may arise due to consumer behaviour such as increased demand or a new connection. This provides greater scope for a variety of alternate options, particularly given the geographic concentration of the need. Such planning is typically expressed in terms of a need to change or extend existing networks and there is a possibility that non-network alternatives can achieve market and community cost benefits at an overall reduced cost. The work and cost tends to be suited for large scale capital intense projects. Except for very large typically complex assets, such as the previously mentioned SVC or a large generator, the distribution asset components are simple and basic devices, such as poles and cross-arms or circuit breakers. In the absence of any need for augmentation, the replacement need is spread across time and geography rather than one-off capital intensive projects. It should be noted that the viability of alternative options in Ergon Energy's distribution area is yet to mature to a stage where such an alternative represents a more economically efficient investment decision. Ergon Energy has been required to undertake only 2 RIT-Ds since its introduction in January 2014, and neither of these has yielded a viable alternative solution.

2. (a) Are the current annual planning reporting requirements in the NER relevant and likely to be useful for replacement expenditure?	Ergon Energy notes that the annual planning review requirements in 5.13.1 of the National Electricity Rules (NER) requires each DNSP to identify, based on the forecast maximum demand, limitations on the network caused by the requirement for asset refurbishment or replacement. While the reporting requirements under Schedule 5.8 of the NER do not require this level of review to be published, it does require a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2M or more that are to address a refurbishment or replacement need. Ergon Energy does not currently report on projects which are still in the planning or concept stage, as they may not proceed. As such, Ergon Energy agrees that the current annual planning reporting requirements in the NER are relevant and would require minimal amendment to apply to replacement expenditure.
(b) If any, where are the gaps in the current annual planning reporting requirements in the NER for replacement expenditure?	Ergon Energy suggests there are no significant gaps in the annual planned reporting requirements in the NER for replacement expenditure. Notwithstanding, Ergon Energy is not opposed to minimal changes to the NER to extend current reporting requirements to replacement expenditure, where an identified benefit is apparent, and the benefit of doing so would outweigh any associated incremental costs.
3. (a) What do NSPs currently do to plan for asset replacement in practice?	Ergon Energy has policies and plans in place to provide a safe, reliable network that delivers quality of supply and complies with regulatory requirements, as well as ensuring optimum asset life. These policies and plans define the inspection and maintenance requirements of each type of asset. Asset life optimisation takes into consideration equipment degradation and failure modes as well as safety, environmental, operational and economic consequences. Ergon Energy's approach to managing the risk of asset failures is consistent with regulatory requirements including the *Electricity Act 1994* (Qld), *Electrical Safety Regulation 2013*, and the *Electrical Safety Code of Practice 2010 – Works.* Ergon Energy distinguishes between expenditure for: • Protective refurbishment and replacement, where the objective is to renew assets before they fail in service by predicting the assets' end-of-life based on condition and risk; and • Run to failure refurbishment and replacement, which includes replacing assets that have failed in service or replacing those that are believed to fail before the next

inspection.

A proactive approach is undertaken typically for high-value, discrete assets, such as substation plant, where Ergon Energy holds plant information and/or condition data. This information is used where analysis shows that proactive replacement or refurbishment capital expenditure (capex) is the most prudent and efficient approach to achieve required quality, reliability, safety and environmental performance outcomes, having regard for the whole-of-life equipment cost. The consequence of failure impacts the priority for replacement of the asset in the program.

Low value assets, where it is not economic to collect and analyse trends in condition data, are allowed to run to near-failure but with minimal or no maintenance intervention. These assets are managed generally through an inspection regime that is developed and undertaken in accordance with various regulatory instruments. The objective of this regime is to identify and replace assets that are expected to fail before their next inspection. However, low value assets that have higher than expected failure rates, or high levels of risk upon failure, may generate targeted replacement programs.

The safety and reliability performance of assets is monitored to identify emerging equipment performance issues. This information is analysed, along with age, condition and obsolescence of assets, to develop maintenance, refurbishment and replacement programs. These activities also facilitate negotiated delivery commitments from service providers, and the prudent physical and financial delivery of programs.

Current asset information, engineering knowledge and practical experience is used to predict future asset condition, performance and risk of failure for network assets. Ergon Energy currently utilises Condition Based Risk Management (CBRM) methodology for evaluating condition-related risk for the higher value asset classes within a substation. In these cases the effort required to develop and maintain CBRM models is warranted. For other asset classes a formal asset class risk assessment is conducted that documents the risks associated with asset failure and mitigation measures implemented.

The outputs from CBRM, Health Indices, are used in conjunction with an engineering assessment to form the basis of the application of the risk based methodology. The risk based methodology allows Ergon Energy to rank projects based on their consequence of failure in addition to their probability of failure. The development of the asset investment plan and specific projects are based on the risk score in conjunction with the engineering assessment and optimised to derive the asset investment program.

(b) To what extent does this address the perceived problems identified by the AER?	Ergon Energy suggests that employing this strategy, along with reporting on it in our DAPR serves to address the perceived problems identified by the AER. It should be noted that any information provided in this manner can never be guaranteed to be without error. Despite best planning and asset modelling, assets may fail unexpectedly. Therefore, Ergon Energy suggests that any increased reporting designed to provide greater transparency in DNSP asset replacement planning should contain appropriate caveats, and hence may be of limited value to energy market stakeholders.
Issue 2: Annual planning reporting requirements on replacement expenditure	
4. To what extent would the proposed information to be reported in the APRs be useful for energy market stakeholders, including non-network service providers, network service providers, connection applicants and the AER, and why?	Ergon Energy cautions that without suitable context, reporting the proposed information in the APRs may mislead non-network service providers and some connection applicants. Ergon Energy suggests that this information would possibly be of greatest benefit to generation connection applicants. Knowledge of potential constraints due to planned asset retirement would allow these stakeholders to make decisions on where to connect in order to provide an alternative solution or where not to connect if supply cannot be guaranteed. Notwithstanding, it should be noted that this sort of information is typically made available during early connection enquiries, when suitable context can be offered. Ergon Energy suggests that there is unlikely to be additional benefit to the AER, as the existing rigorous planning process already feeds into the development of the regulatory proposal which presents the most efficient forecast investment expenditure given current knowledge of the regulated businesses.

5. (a) Is it appropriate that the scope of the new reporting requirements include planned asset de-ratings as well as planned retirements?	Over time, asset condition slowly degrades, influenced by a range of factors such as the physical environment, duty cycle performance, loading and maintenance practices. This has the effect that design margins eventually become impacted and finally compromised. Derating of plant capacity acts to impose additional operating limitations over original design constraints and is one method of achieving life extension of the asset at the expense of operational capability. Derating is typically achieved by condition assessment and analysis. Further, derating is generally by small percentage increments relative to the original design quantities – for example a 1-5 per cent reduction in transformer cyclic capacity. As such, Ergon Energy does not believe there is any benefit to be gained by reporting on all asset deratings. Rather, Ergon Energy suggests that reporting on limitations caused by asset de-ratings would represent a more prudent approach to increased transparency in this area.
(b) To what extent does this add to the administrative burden for NSPs?	Ergon Energy believes that the administrative burden of reporting on all asset de-ratings is likely to outweigh the benefits of doing so. As suggested above, Ergon Energy recommends reporting on limitations caused by asset de-ratings would provide a more efficient approach.
6. (a) Should all assets be reported on by NSPs in their annual planning report or are only certain asset types relevant?	As noted in our response to Question 3(a) above, it is not economic to collect and analyse trends in condition data for low value assets. As such, it would be similarly uneconomic to have to report on these asset types in the DAPR. Furthermore, it is unlikely that a viable alternative solution would be identified to the replacement of these low value asset types.
(b) What types of asset should be subject to reporting requirements by NSPs and what should not?	Ergon Energy suggests that reporting only on low volume very high cost assets would be prudent. Furthermore, Ergon Energy suggests that an appropriate cost threshold should be set – similar to that required under Schedule 5.8 (g) of the NER.
7. (a) Is the proposed AER network retirement reporting guidelines the appropriate means of requiring NSPs to report on certain asset types and not others or would an alternative mechanism be more appropriate?	Ergon Energy agrees that the proposed guidelines are the most appropriate mechanism to require NSPs to report on certain asset types and not others, should it be agreed that additional reporting obligations are to apply. However, Ergon Energy suggests that appropriate consultation is given to the development and review of the guidelines, and that any proposed change to the guidelines as a result of a review is consistent with current review requirements under Chapter 5 of the NER.

(b) If an AER guideline is appropriate, what should it contain and how should the AER be guided in its development?	Ergon Energy considers that development of the proposed guidelines should be guided by the suggested principles with due consideration of the cost vs benefit of any inclusions for reporting. Furthermore, Ergon Energy believes that the guidelines only deal with the asset classes to be reported on and an associated cost threshold, as suggested in our response to Question 6(b).
(c) In addition, what would the appropriate process be to make and review an AER guideline?	Ergon Energy suggests that the development and review of the proposed guidelines should be consistent with the distribution consultation procedures as prescribed in Part G of Chapter 6 of the NER. Furthermore, Ergon Energy suggests that a review period should be consistent with similar review requirements under Chapter 5 of the NER.
8. (a) Should the AER guideline also set out principles and a broad approach that NSPs must follow in deciding whether to plan to retire assets?	Ergon Energy does not support the inclusion of guiding principles that NSPs must follow in deciding whether to plan to retire assets. Ergon Energy believes that NSPs are best placed to make these decisions in accordance with existing legislative frameworks. Refer to our response to Question 3(a) which notes legislation with which Ergon Energy currently complies in making refurbishment / replacement decisions.
(b) What should these principles and the broad approach be?	Not applicable – Ergon Energy does not support the inclusion of such principles and guiding approach.
9. Compared to the current arrangements, how much additional reporting by NSPs would be required under the AER's proposal? What would be the impact on NSPs?	As noted in our response to Question 2(a), DNSPs already report on committed investments to be carried out within the forward planning period with an estimated capital cost of $2M or more, including an options analysis of these investments. Retaining the suggested reporting cost threshold, and subject to the level of inclusions for reporting provided for in the proposed guideline, Ergon Energy estimates the proposed reporting requirements will not significantly increase the regulatory burden and the associated incremental cost will be negligible. Notwithstanding, Ergon Energy notes that every additional reporting requirement increases the regulatory burden and there is likely to be a threshold beyond which the perceived benefit does not translate to a benefit to consumers or a net benefit to NSPs.
Issue 3: Application of regulatory investment tests to replacement expenditure	
10.Will extending the regulatory investment tests to replacement capital expenditure benefit energy market stakeholders, including non-network service providers, network service providers and the AER,	Ergon Energy does not believe that extending the RIT to replacement expenditure will yield any significant benefit in our distribution area. As noted in our response to Question 1(b), Ergon Energy has been required to perform 2 RIT-Ds since its introduction in 2014, both involving lengthy timeframes and 100s of hours of overhead costs, and neither has yielded a

and why?	viable alternative solution. Moreover, it is important to note that the physical condition of a particular asset is not only affected by a load profile, but also aging and techno-physical conditions which are affected by a number of other factors. Non-network solutions typically impact on load and may not remove other risks associated with the safety of our assets. As such, it is not clear that an appropriate alternative solution for like-for-like replacement will exist. Ergon Energy suggests that alternative mechanisms for engaging with the market may be more efficient, such as a portal or interactive map showing areas where high cost replacement or refurbishment projects may arise. Ergon Energy currently engages with the market through a network incentive map which was specifically developed for augmentation projects. However, Ergon Energy is currently exploring opportunities to create incentive areas based on any network investment to provide an appropriate demand side solution which can mitigate the need for the investment. These mechanisms can provide energy market stakeholders and non-network service providers with early information and an avenue for engagement with DNSPs. Note that potential future projects may not eventuate, as noted in our response to Question 3(b), if an asset fails prematurely and an immediate response is required. Notwithstanding, this mechanism will also allow DNSPs to assess the viability of further formal engagement with the market without jumping straight to a RIT process where no additional benefit will be derived.
11. Should the regulatory investment tests also apply to maintenance and refurbishment expenditure or should these categories of expenditure continue to be exempt from the tests?	Ergon Energy does not support the inclusion of maintenance expenditure in the RIT process. Such expenditure usually involves individual and low cost items, and Ergon Energy currently operates an open tender process for general maintenance requirements. While Ergon Energy does not believe there will be a net benefit from extending the RIT process to replacement / refurbishment expenditure, only large items consistent with the suggested reporting requirements should be considered for inclusion.
12. Should the cost thresholds for asset replacement projects be the same as cost thresholds for network augmentation projects?	Ergon Energy seeks clarification on how the cost threshold is proposed to be applied to the RIT. It appears that the intent is for the threshold to include both augmentation expenditure (augex) and replacement expenditure (repex). This is, if the current threshold is retained, any project comprising a total of capital expenditure (including augex and repex) of greater than $5M will require a RIT-D. For example, an individual project with augex of $3M and repex of $2 would previously be exempt from the RIT-D process but would now be captured.

	Ergon Energy estimates that if the threshold were to apply separately to repex, then at the same level, it is likely that only 1 or 2 projects would ever be subject to this process. However, a combined cost threshold is likely to capture more projects each year, and this is likely to result in a significant increase in overhead costs for no additional benefit. This is particularly due to the increased complexity for assessing an alternative solution which impacts on power quality or reliability as these are much more complex operational and commercial arrangements. Reliability is especially complex as a network failure would result in an outage to a network segment and having demand side options will largely not result in the mitigation of an outage. As such, this increase in overhead costs will ultimately flow through to customers in the form of increased tariffs, from which customers will see no additional benefit. Therefore, Ergon Energy recommends that if the threshold is to apply separately, the same threshold as augex would be appropriate to avoid additional complexity and ambiguity (noting that Ergon Energy does not perceive there will be a net benefit), and if a combined threshold is to apply then the current level should be retained or increased.
13. Is it appropriate for a regulatory investment test to not be required where an NSP considers a like-for-like replacement of the asset is the only option to address the problem?	Ergon Energy supports the exemption from the RIT process where an NSP considers a like-for-like replacement of the asset is the only option to address the problem. In particular, there are very few options for replacements on a radial network such as Ergon Energy's. For example, a circuit breaker at the beginning of a radial network provides a necessary protective function to achieve the safety objectives of the National Electricity Objective (NEO). Even if a non-market alternative were available, then short of dismantling the radial network (i.e. isolating the load permanently from the grid), the circuit breaker will always be required in order to achieve the requisite safety function. Whereas, on a solidly meshed network alternative options such as load shifting may be possible, but at the cost of increased reliability performance degradation over time. In addition, if the like-for-like replacement cost of the asset is low (and typically most asset components are low) employing a RIT would substantially escalate the replacement cost, which would not be in the long term interests of all customers.

14.(a) Is the proposed requirement for NSPs to publish an exemption report where there is no alternative to like-for-like replacement appropriate?	Ergon Energy does not support the publication of an exemption report where it deems there is no alternative to a like-for-like replacement. Ergon Energy suggests that publication of a report is not consistent with the current requirements for augmentation projects and at a minimum the requirement for both project types should be harmonious – that is, a notice pursuant to clause 5.17.4(d) of the NER should suffice for replacement projects as well. Alternatively, Ergon Energy suggests this information could similarly be published in the DAPR.
(b) Do the benefits of this mechanism outweigh the administrative costs that it may impose?	As noted earlier, Ergon Energy suggests the publication of a separate report increases overhead costs and contributes to the regulatory burden where there is no apparent benefits. Therefore, any perceived benefit will be outweighed by the administrative costs imposed.
(c) Is there an alternative mechanism which would be more appropriate?	Ergon Energy does not consider the requirement for any alternative reporting mechanism to be appropriate where there is no alternative to like-for-like replacement. As noted above, Ergon Energy believes that any requirement merely imposes a regulatory burden that increases customer costs in the long term. Ergon Energy considers that an inclusion in the DAPR would be likely to achieve the least additional cost burden.
15.(a) What information should NSPs be required to provide in an exemption report?	Ergon Energy currently reports on asset replacement programs by class in the DAPR. There would be minimal additional burden by noting in this section where there are no like-for-like alternatives. As noted above, Ergon Energy does not support the requirement to publish an exemption report, and no additional information should be required that is inconsistent with clause 5.17.4(d) of the NER.
(b) Is it appropriate that an NSP has to provide a summary of an exemption report to AEMO within 5 business days and to interested parties, on request, within 3 business days?	Ergon Energy does not support the provision of a summary of the exemption report to AEMO or interested parties. Ergon Energy suggests that this only imposes an unnecessary additional administrative burden.
(c) Do stakeholders agree that AEMO must publish the exemption report on its website within 3 business days?	Not applicable – refer above.

16.(a) Is it appropriate that parties can raise a formal dispute with the AER on the conclusions of an exemption report published by an NSP?	Notwithstanding our non-support for a requirement to publish an exemption report, Ergon Energy generally supports the ability for parties to raise a formal dispute with the AER where the provisions of the NER have not been applied correctly. Ergon Energy notes that the current dispute provisions applying to the RIT-D process under Clause 5.17.5 of the NER relate only to the final project assessment report, and not to a Notice published under clause 5.17.4(d) which states that a RIT-D proponent determines on reasonable grounds that there will not be a non-network option that is a potential credible option, or that forms a significant part of a potential credible option, for the RIT-D project to address the identified need. As such, the proposal to raise a formal dispute with the AER on the conclusions of an exemption report is not consistent with the broader RIT-D framework.
(b) Is 30 business days, as proposed, the appropriate timeframe for allowing interested parties to raise a dispute with the AER?	As above, Ergon Energy generally supports the ability for parties to raise a formal dispute with the AER, where it is consistent with the provisions under Clause 5.17.5 of the NER.
(c) Is 31 business days after publication of an exemption report the appropriate timeframe for an NSP to wait to undertake a like-for-like replacement where no dispute is raised?	As above.
(d) If an exemption report is determined by the AER to be non-compliant, should the NER explicitly exclude an NSP from being reliant on the report to carry out a like-for-like replacement?	As above.
Issue 4: Issues specific to Victoria	
17. (a) Would AEMO or AusNet Services be the most appropriate body to report on the proposed additional annual reporting requirements at the transmission level in Victoria and why?	Nil comment
(b) Would AEMO or AusNet Services be the most appropriate body to apply the RIT-T for replacement expenditure in Victoria and why?	Nil comment

Issue 5: Other NER changes proposed by the AER	
18.(a) Are the additional changes proposed by the AER appropriate and useful to stakeholders? (b) What compliance burden would arise for NSPs? (c) As these requirements currently apply in a limited way in the NER, how useful have they been to date?	Ergon Energy does not oppose the additional changes proposed to the NER.
Issue 6: Transitional arrangements	
19.What transitional arrangements should be put in place to allow NSPs and the AER to be able to comply with the proposed rule if it were to be made?	Ergon Energy suggests a similar transitional process should apply as when the RIT-D process replaced the Regulatory Test process. That is, any current committed projects should be exempt from the process. Furthermore, Ergon Energy suggests that an appropriate transitional period would be required, which will allow for NSPs to implement any required system and process changes. Ergon Energy is unable to quantify this period until further detail on requirements is established.