14 May 2008

Attention: Mr Chris Pattas
Australian Energy Regulator
GPO Box 520
MELBOURNE VIC 3001

Dear Mr Pattas

National Guidelines, Models and Schemes

ENERGEX Limited (ENERGEX) is pleased to make a submission to the AER's proposed guidelines, models and schemes released on 1 April 2008. ENERGEX's comments are in relation to the following:

- Proposed Post-tax Revenue Model (PTRM);
- Proposed Roll Forward Model (RFM);
- Proposed Cost Allocation Guidelines (CAG);
- Proposed Efficiency Benefit Sharing Scheme (EBSS); and
- Proposed Service Target Performance Incentive Scheme (STPIS).

In developing a national framework to apply to distribution network businesses, the AER should be cognisant of the diverse range of regulatory approaches currently in place in the various jurisdictions. There is a disparate state of maturity in regulatory reforms amongst the NEM jurisdictions. Given these factors, a "one size fits all" approach to guidelines, models and schemes may not be appropriate at the commencement of national regulation of DNSPs.

ENERGEX's detailed responses to each of the issues are provided in the attached document. We would like to highlight the following key points of concern:

- The information requirement, associated cost and level of detail required to comply with CAG and the Cost Allocation Methodology (CAM);
- The basis of indexation of the RAB in the RFM;
- The impact on cash flow arising from the change in approach on the timing of return on asset and return of asset in the PTRM;
- The symmetrical nature of the EBSS on OPEX; and
- The level of information, reporting requirements and associated system and process changes required arising from implementation of STPIS.

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ENERGEX would also appreciate the opportunity to further discuss the issues raised in this submission with the AER.

If you have any questions in relation to any of the matters raised, please contact either myself on (07) 3247 6409 or Sue Lee on (07) 3247 6495.

Yours sincerely

Kevin Kehl

Kevin Kehl
Director Revenue Strategy

ENERGEX's Response to the AER's National Guidelines, Models and Schemes

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1 Roll Forward Model (RFM) And Post Tax Revenue Model (PTRM)

General Comments relating to both the RFM and PTRM

- In general ENERGEX supports both of the proposed models.
- Clarification is sought on the term Regulatory Asset Base (RAB) with reference to 'standard control services' and 'direct control services'. In determining the Building Block (Clause 6.4.3(a)) reference is made to Clause 6.5.1(a) of the National Electricity Rules (NER) which states that the RAB for a DNSP is the value of those assets used to provide 'standard control services'. It is unclear where 'alternative services' are considered.
- Following discussion with other DNSPs at the AER forum ENERGEX requests that the AER expand both models to accommodate more asset categories (propose 30).
- ENERGEX would like clarification on the escalation of real CAPEX by WACC in each of the models. In the PTRM the Real Vanilla WACC is applied to real CAPEX however in the RFM Nominal WACC is applied to the derived real CAPEX.

Specific comments in relation to the RFM

- S6.2.2(7) states "the value of the relevant asset as shown in independently audited and published accounts". ENERGEX has interpreted this statement along with the Rules, RFM handbook and Explanatory Statement to mean that the CAPEX used to populate the RFM is to reflect the CAM approved for use in the current regulatory period (i.e. the approved CAM during the years relating to the RFM), and not the CAM proposed for use in the following regulatory period. ENERGEX seeks confirmation that this interpretation is correct.
- Clarification is sought on the basis for determining the rate to be used in the model for the indexation of the RAB. ENERGEX believes a rate that more accurately reflects the cost components of the asset base and accounts for prevailing market conditions is more appropriate than a generic CPI rate.

Specific comments in relation to the PTRM

- Return of asset and return on asset calculations are a departure from ENERGEX's current regulatory arrangements under the QCA and will impact negatively on cash flows. ENERGEX would like assurance from the AER that smoothing mechanisms will be employed to mitigate any negative impact.
- The PTRM handbook references all items on the input sheet with the exception of the newly added pricing data. The handbook should discuss these items and outline their purpose and use.
- Clarification is sought on the purpose/use of the notional revenue information derived in the PTRM.

- ENERGEX would like clarification of the relationship between the notional pricing derived from the PTRM and the 5 years of pricing information to be included in the Regulatory Proposal.

2 Cost Allocation Guideline (CAG)

General Comments

Cost allocation for electricity distribution and transmission

ENERGEX notes that the Proposed Distribution CAG broadly replicates the *Electricity Transmission Network Service Providers' Final Cost Allocation Guidelines* (September 2007). However, the significantly wider range of services provided by DNSPs results in considerably greater complexity when it comes to allocating costs appropriately across all services. As a result, a more complex and time consuming internal cost allocation process is required by DNSPs for regulatory purposes than for TNSPs.

In this regard, the principle nature of the Proposed Distribution CAG makes it very difficult for ENERGEX to fully assess the information requirements and associated compliance costs it will entail in relation to preparation of its Cost Allocation Method (CAM) under the Rules. ENERGEX has previously expressed concerns about the development of information requirements for DNSPs commensurate with the TNSP Information Guidelines.[1]

ENERGEX notes that the distribution information requirements will primarily be a function of the nature of regulatory information instruments yet to be developed by the AER. The role to be played by such instruments in the AER's cost allocation approval process is also not identified in the Proposed Distribution CAG.

In relation to the Proposed Distribution CAG, ENERGEX envisages potentially high compliance costs through requirements for preparation of working papers to justify each non-causal allocation when submitting financial information based on its CAM, as well as through the way in which the AER may interpret materiality in relation to specific shared cost allocations.

It is also difficult to consider the full implications of the cost allocation requirements likely to be imposed on DNSPs because although the Explanatory Statement notes that the Proposed Distribution CAG will only concern cost attributions and allocations to the classified service level, these will need to be considered in conjunction with the Regulatory Information instruments. If the CAG was to go beyond the service level it may result in substantial additional costs to the DNSP. ENERGEX notes that according to the AER, the final step of allocating costs for pricing purposes will be dealt with separately through future regulatory information instruments.

As previously mentioned in the comments relating to the RFM, ENERGEX seeks confirmation that prior CAPEX will not have to be restated to reflect the proposed CAM for use in the RFM. Prior CAPEX will only be restated for information purposes in

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1 ENERGEX (2007), Electricity Transmission Network Service Providers – Information Guidelines (July).

relation to the application and assessment of the new CAM, not for determining the DNSPs Regulatory Asset Base.

In relation to the provision of restated historical CAPEX, ENERGEX is concerned that if the requirement was for a period of more than two years, significant compliance costs would arise. In this case ENERGEX would like the AER to consider providing either the fair and reasonable out of pocket costs for such an exercise, or to apply an 'undue cost and effort' test against these information requests. In considering this, ENERGEX seeks guidance from the AER on their definition of 'undue cost and effort'.

Finally, there are a number of potentially important transitional issues facing the Queensland and South Australian DNSPs in relation to the development of their respective CAMs which do not receive any recognition in the Proposed Distribution CAM or Explanatory Statement. Of particular concern to ENERGEX is the relationship between the development of its CAM and other aspects of its Regulatory Proposal for the 2010-2015 regulatory control period. In particular, the AER's decision in relation to ENERGEX's service classification proposal and the development of capital and operating cost forecasts, including the extent to which historic capital and operating expenditure data may need to be re-cast, have not yet been finalised.

Purpose of cost allocation and alternative approaches

ENERGEX regards cost allocation as a means to an end, the end being to inform the setting of electricity distribution service prices which are consistent with the national electricity objective.

The focus of ENERGEX's internal cost allocation processes in the 2010-2015 regulatory control period will be the appropriate allocation of costs across each classified distribution service and a small number of unregulated services that it provides. Following the Queensland Government's sale of ENERGEX's retail arm in 2007, the historical primary ring fencing objective to ensure costs are appropriately allocated between retail and distribution activities, is no longer applicable in ENERGEX's case.

In ENERGEX's view, the major difficulty in undertaking cost allocation for electricity distribution (and economic infrastructure more generally) is the existence of significant common or joint costs. In contrast to directly attributable costs, there is no 'right' way of allocating these common/joint costs.

The standard regulatory approach to cost allocation for pricing purposes in Australia has been the establishment of incremental and stand alone costs of service provision, such that individual consumers or groups of consumers pay no more than the stand alone cost of supply and at least pay the incremental cost of supply of a particular service. This approach is reflected in Clause 6.16 of the NER.

The main implication of this approach is that by ensuring prices are at least greater than incremental cost, any such allocation is efficient and cannot be improved upon. However, difficult equity issues can arise in relation to the allocation of common/joint costs across individual consumers or groups of consumers.

As a result, the accounting technique of fully distributed costs has often been used by infrastructure providers, and accepted by regulators, such that all network costs are allocated across the services being supplied. Under this approach, common/joint costs can be allocated to services on the basis of several different methods. For example, on the basis of a service's share of output/revenue relative to total output/revenue or on the basis of a service's share of directly attributable costs relative to total attributable costs. However, this average cost approach has limited regard to economically efficient outcomes and an element of judgement is necessary in applying the fully distributed cost allocation approach.

The level of granularity that an electricity distribution network wishes to allocate to, can impact on the proportion of costs that can be directly allocated or allocated on an appropriate causation basis. Depending on the level of granularity of cost allocation there may be some proportion of common/joint costs that cannot be allocated on a causal basis. Consequently, the AER's stated objective in the Explanatory Statement to prevent cost shifting from unregulated sections of a business to regulated sections of a business will require the application of careful judgement in practice. Beyond ensuring that directly attributable costs have been appropriately assigned to service classifications, there will be generally be more than one defensible allocation of common/joint costs across services.

Moreover, recognition of economies of scale and scope in network service provision is likely to be important in the allocation of costs across different service classifications. This is because the existence of such economies allows particular services to be supplied at incremental cost price. Such pricing does not represent cross subsidisation of those services and hence is efficient. Given the AER has stated that the CAG is an important and necessary instrument to prevent subsidisation of contestable activities, a demonstration that all prices are set above incremental cost would be sufficient to meet this objective, with the allocation of common/joint costs not relevant in this case.

Ultimately, ENERGEX agrees with the AER that the assessment of an appropriate cost allocation method should have regard to the national electricity objective.

Responses to specific AER questions raised in Explanatory Statement

Q1. Are the working assumptions used to prepare this discussion paper and the proposed guidelines appropriate, in particular: *The CAG will be a stand-alone document.*
ENERGEX does not consider the CAG to be truly a stand alone document because yet-to-be-developed regulatory information instruments in relation to the detail of preparing cost allocation documentation, regulatory reporting, cost and financial auditing, and cost allocation for pricing purposes will all directly impact on a DNSP's cost allocation processes.
Q1. Are the working assumptions used to prepare this discussion paper and the proposed guidelines appropriate, in particular: *The guidelines will only deal with cost attributions and allocations down to the services level, not individual prices for different categories of services.*
In light of the assumption that the CAG will only deal with cost attributions and allocations down to the services level, ENERGEX queries the intent of Clause 5.1 of the Proposed Distribution CAG, which provides that a DNSP is to apply its CAM in preparing prices for a negotiated distribution service. ENERGEX notes that costs attributions and allocations for pricing purposes will be the subject of regulatory information instruments that are yet to be developed. ENERGEX is concerned that while the regulatory information instruments may be tailored to the circumstances of DNSPs, they could impose an excessive compliance burden on DNSPs. As previously noted, the significant role envisaged for regulatory information instruments in a DNSP's cost allocation process means that the CAG will not be truly a stand alone document.
Q1. Are the working assumptions used to prepare this discussion paper and the proposed guidelines appropriate, in particular: *All revenues, costs, assets and liabilities of regulated business will have their origin in statutory accounts, although a single set of regulatory accounts could potentially draw from the statutory accounts of multiple entities.*
ENERGEX considers this assumption to be reasonable and consistent with standard regulatory practice.

Q1. Are the working assumptions used to prepare this discussion paper and the proposed guidelines appropriate, in particular: *Regulatory accounts requirements take precedence over statutory accounts requirements for regulatory purposes.*
ENERGEX considers that this working assumption requires more explanation given regulatory accounts will generally be derived from statutory accounts. In particular, it is not clear whether the AER envisages any departures from Australian Accounting Standards in the preparation of regulatory accounts, including regulatory accounting requirements potentially exceeding statutory accounting requirements. For example, in relation to the level of reporting detail, application of materiality thresholds and capitalisation policies. In this regard, ENERGEX seeks guidance from the AER about how it intends to interpret the broad definition of "material" under the Proposed Distribution CAG. While ENERGEX recognises that assessments of materiality in relation to financial data will always entail an element of judgement reflecting the specific circumstances of a business, quantitative guidance should be incorporated in the Proposed Distribution CAG. This is particularly the case for matters such as cost allocation, where it is possible for a DNSP to mechanically attribute, albeit not without significant administrative effort and cost, every dollar of distribution cost across distribution service classifications. As a result, ENERGEX proposes that a quantitative threshold should be applied in relation to the allocation of shared costs. In ENERGEX's view, if any departures from Australian Accounting Standards are envisaged by the AER, they should be clearly identified in the CAG. It is inappropriate that any such departures be reflected in regulatory information instruments, which are not subject to public scrutiny.
Q2. Is it possible to derive a single set of allocators applicable to all network service providers? *Q3. If yes, would it be appropriate to do so?* *Q5. Is there merit in the regulated businesses working together to produce a future industry standard for the attribution and allocation of costs?*
ENERGEX considers that, in practice, it would be very difficult to derive a single set of allocators applicable to all DNSPs given their widely varying legal, operational and network characteristics. ENERGEX agrees with the AER's summary of these differences provided in its Explanatory Statement. The only benefit identified in the Explanatory Statement for the adoption of a single set of allocators is that they could be applied consistently in all regulated DNSPs. However, it is not clear to ENERGEX how such uniformity would be consistent with promoting economic efficiency in the use of electricity networks given the potential for uniformity in cost allocation to be reflected in rigidity in distribution service prices. As a result, ENERGEX is strongly of the view that the AER should not develop a 'one size fits all' set of cost allocators. For the same reasons, ENERGEX does not support the development of a future industry standard for the attribution and allocation of costs.

In this regard, ENERGEX strongly agrees with the AER's view, expressed in the Explanatory Statement, that the provision of relevant, reliable and consistent information by a DNSP over time is preferable to obtaining information that is strictly comparable between different DNSPs at any point in time.

Q4. Should the regulated business or the AER select the allocators for shared costs?

In ENERGEX's view, the DNSP should propose cost allocators for the AER's approval, subject to relevant NER requirements. Each DNSP is best placed to propose cost allocators based on knowledge of its business and its accounting systems. ENERGEX notes that the preparation of its CAM and the selection of allocators will also drive internal reporting requirements. The regulated business selecting the allocators is consistent with the Regulatory Proposal approach used for Revenue Determinations in the NER.

In relation to the allocation of shared costs, ENERGEX has a concern about Clause 2.2.4(d) of the Proposed CAG, which states that the AER expects only to accept a non-causal basis of allocation if the DNSP can demonstrate that there is likely to be a strong positive correlation between the non-causal basis of allocation and the actual causal basis of the shared costs incurred in the provision of a service.

In ENERGEX's view, this is an unreasonable test to apply. By definition, a non-causal basis of allocation is unlikely to be positively correlated with a causal allocator otherwise a causal allocator would most likely be available. In practice, this requirement will likely result in some shared costs not being allocated because neither a causal basis nor non-causal basis (that is positively correlated with a causal basis) can be identified. ENERGEX accepts that a DNSP needs to justify a defensible basis for the choice of a non-causal allocator and the Proposed Distribution CAG (Clause 2.2.4 (c)(4)) provide for such an outcome. As a result, ENERGEX suggests that Clause 2.2.4(d) be removed from the Proposed Distribution CAG.

Q6. Should cost allocation be allowed using the avoided cost method and, if so, under what circumstances should it be allowed?

ENERGEX agrees with the AER that there are a variety of cost allocation methods available to DNSPs, including fully distributed cost, activity based costing, marginal cost, incremental and avoided cost.

In practice, there is likely to be little difference between the use of the avoidable cost and incremental cost allocation approaches to set prices. This is because the cost saved by not supplying a service (avoidable cost) will generally be broadly comparable with the additional cost of making a service available (incremental cost). Given the symmetrical nature of incremental and avoidable costs ENERGEX questions the rationale of allowing the use of incremental costs whilst restricting the use of avoidable costs to immaterial amounts.

ENERGEX notes that Clause 6.18 of the NER, which establishes the framework for the allocation of costs for pricing purposes, refers to tariff class revenues lying between a stand alone cost ceiling and avoidable cost floor, which effectively endorses the avoidable cost approach.

Under the Proposed Distribution CAG, the onus is on the DNSP to justify use of the avoidable cost allocation method to the AER. In ENERGEX's view, this is a reasonable compromise position on the issue and recognises that the DNSP is best placed to choose cost allocators for its business which are then subject to AER approval. However, for the reasons discussed above, ENERGEX does not support a restriction on the use of the avoided cost method to immaterial costs only. In ENERGEX's view, such a restriction is inconsistent with Clause 6.18 of the NER.

Q7. Is it appropriate that the scope of the regulatory audit (as it relates to cost allocation) only assesses whether costs have been appropriately attributed or allocated, not whether the allocators themselves are most suitable?

ENERGEX agrees with the AER that there are benefits from a requirement for up-front approval of shared cost allocators rather than approval after they have been applied. This is particularly the case for the preparation of operating and capital expenditure forecasts in its Regulatory Proposal and the preparation of certified annual financial statements. As a result, ENERGEX agrees with the AER that this will allow the regulatory audit to relate only to whether costs have been appropriately attributed or allocated, not whether the allocators themselves are appropriate.

However, more broadly, ENERGEX has concerns about the lack of information provided in the Proposed CAG in relation to the nature and conduct of regulatory audits that will be undertaken for a DNSP's Revenue Proposal and historic and forecast financial information. While ENERGEX supports AER's position that audit arrangements should have regard to the individual characteristics of regulated businesses, the Proposed Distribution CAG could result in a much larger auditing burden on ENERGEX than currently applies. Consequently, ENERGEX considers that more detail on the AER's intended audit requirements should be specified in the Proposed Distribution CAG.

3 Efficiency Benefits Sharing Scheme (EBSS)

General Comments

ENERGEX is generally supportive of the direction that the AER has adopted in the development of the Efficiency Benefit Sharing Scheme (EBSS). In particular, ENERGEX welcomes AER's decision to exclude CAPEX and distribution losses from the efficiency benefits scheme.

However, ENERGEX holds residual concerns about the symmetrical nature of the EBSS on OPEX. ENERGEX still believes the symmetrical nature of the scheme results in double penalisation to DNSPs, firstly through the original additional OPEX (that customers have not funded) and then secondly through the EBSS penalty. It appears DNSPs pay twice regardless of whether the OPEX was efficient or not.

ENERGEX is also not convinced that by excluding uncontrollable costs from the scheme, the risk of negative carry-over will be sufficiently reduced. From a processing, compliance and reporting viewpoint, it would be much simpler and less costly to remove the process of negative carryovers and instead apply the approach discussed at the AER forum. The alternative approach discussed at the forum involved reviewing and comparing the year 4 OPEX with OPEX undertaken in other years of the regulatory period. The year 4 OPEX could be adjusted for any inconsistencies that bias the future OPEX forecast for the DNSP.

In addition ENERGEX believes that the AER should re-consider its decision not to allow negative carry-overs to be offset against future positive carry-over amounts. This is particularly relevant if carry-over amounts are significantly material as their impact on the ARR may lead to significant price volatility for customers.

ENERGEX seeks further clarification on the additional information that will be required to calculate the efficiency gains and losses. The AER needs to ensure that this will not be an onerous exercise that leads to significant administrative costs.

Specific Comments on the proposed EBSS paper

- Section 1.6, Page 1: the last word should be "scheme" not "handbook";
- Section 2.3.3, Page 5: first paragraph "transmission" should be replaced with "distribution" and "TNSP" with "DNSP"; and
- The Explanatory Statement 4.4.2 provides for non-network alternative costs to be excluded from the EBSS, however this not explicitly stated in the Section 2.3.2 of the Scheme.

4 Service Target Performance Incentive Scheme (STIPS)

General Comments

ENERGEX recognises the efforts of the AER to include considerable flexibility in the guidelines for DNSPs. This will be of particular advantage to DNSPs such as ENERGEX who are unfamiliar with operating this type of scheme. Overall, ENERGEX supports the proposed guidelines with some specific comments about aspects of the scheme outlined below.

Responses to specific AER questions raised in Explanatory Statement

Q. The AER would like views on whether there is sufficient clarity in the proposed scheme, so that DNSPs can plan the actions they need to take to be able to comply with the scheme when it is implemented.

ENERGEX seeks further clarification regarding:
• Interaction of STPIS:
  o with MSS targets.
  o with GSL schemes.
  o distribution of the revenue at risk across the suite of parameters.
  o with forecast reliability and customer service improvements incorporated in CAPEX and OPEX.
  o A fully worked example showing interaction of all of the parameters.
• Mechanism for reporting exclusions – what is the mechanism (if any) for the AER to approve exclusions associated with specific events, given 2.5 Beta events are to be reported to the AER annually.
• Parameters
  o Customer service parameter definitions and response times (e.g. telephone answering) for ENERGEX are different to the proposed definition in Appendix A of the scheme. Is there flexibility to propose alternatives?
  o The Customer Service parameter in relation to response to written enquiries is general. The scope of this measure is undefined and may be open to interpretation. How much discretion does the DNSP have to define these?
  o Streetlights – ENERGEX has proposed in its' Stage 1 Framework and Approach that provision of streetlights is not a direct control service and should not be classified (i.e. it is an unregulated service) and therefore should not be included in the STPIS.
• The interaction between customer's propensity to pay, incentive schemes and ongoing performance improvement. ENERGEX seeks to work with the AER to consider and address this issue.
• Mechanism to balance network augmentation with non-network alternatives – it is unclear how this would operate in practice.
• Accuracy of figures in reporting – Under the Queensland Electricity Industry Code, reliability figures are required to be within $\pm 5\%$. ENERGEX seeks clarification regarding treatment of accuracy variations under this scheme.

Q. The AER would like views on the proposed inclusion of planned interruptions in the reliability measures.
ENERGEX is of the view that planned interruptions should be excluded from reliability measures in STPIS as it is inconsistent with the incentive to efficiently maintain a safe network. • ENERGEX's planned outages have increased significantly over past years. This is driven by substantial population growth and network expansion and has been increasing on an incremental basis. • Currently ENERGEX uses alternative strategies to mitigate planned outages (e.g. standby generators). This approach may be adversely impacted in the future by external factors such as fuel conservation and greenhouse emissions which could potential result in increasing planned outages. • From a safety perspective, there is increasing pressure to work "not live", hence, leading to more planned interruptions.
Q. Is the mechanism proposed by the AER to balance the incentive to carry out network augmentation with non-network alternatives under the scheme sufficient? Are there any other mechanisms that the AER should put in place in this regard?
ENERGEX is unclear how the balance between network and non-network solutions will be achieved under the proposed scheme. The availability of non-Network solutions is currently limited and the lead time to implement DSM solutions can be lengthy. It is unclear how the scheme will operate in terms of balancing the incentive for network versus non-network augmentation. Given the lower reliability of non-network solutions which will adversely impact on SAIDI there may be a disincentive to adopt non-network solutions if the scheme does not include the appropriate recognition.
Q. The AER would like views on the proposed approaches for setting incentive rates for the reliability and customer service components of the scheme.
ENERGEX supports a consistent national approach for DNSPs for setting incentive rates. ENERGEX would prefer to adopt a transparent approach and methodology that is used by all jurisdictions that is reflective of current customer responses and responsive to changing attitudes. ENERGEX is concerned about the application of Victorian and South Australian "Willingness to Pay" on the basis that it may not adequately represent jurisdictional characteristics (geography, demographics, variability of storm seasons and growth rates) or the current economic climate and its impact on customers since 2002.

Q. The AER would like views on its proposal to set the overall cap on the s-factor at 3% of revenue.
ENERGEX supports a maximum of 3% revenue at risk, with the opportunity to propose an alternative where it would satisfy the objectives of the scheme. For ENERGEX, 3% represents a potentially substantial high financial risk for the business, given its current profile (high total revenue, high CAPEX & OPEX, & increasing asset base) and inexperience with the scheme.
Q. The AER would like views on the proposed revenue at risk for the customer service component and an individual parameter within the customer service component.
ENERGEX supports a maximum of 1% at risk and a maximum of .5% for an individual parameter.
Q. The AER would like views on the proposed scope of exclusions.
ENERGEX is of the view that the proposed scope should reflect exclusions that apply under relevant industry codes. Exclusion of some but not all events would require dual recording and reporting processes. Therefore, additional exclusions for Queensland from the Electricity Industry Code should be included as shown below. (Other jurisdictions may have other additional exclusions.) • A direction from NEMMCO, a system operator or any other body exercising a similar function under the Electricity Act, National Electricity Rules or National Electricity Law; • Automatic shedding of load of under frequency relays following the occurrence of a power system under-frequency condition described in the power system security and reliability standards; • A direction by a police officer or another authorised person exercising powers in relation to public safety; and • An interruption caused by customer's electrical installation or failure of that electrical installation. ENERGEX notes that while 2.5 beta takes out certain major events, the variability of our storm seasons continues to be of concern. ENERGEX is seeking to address this issue with the AER through the development of new normalising techniques.
Q. The AER would like views on the how the s-factor should be incorporated into the form of control.
ENERGEX would like to work with the AER to gain further understanding of this issue before making further comments.
Q. The AER would like views from stakeholders on the proposed s-bank mechanism.
ENERGEX supports the inclusion of an s-bank mechanism. However, ENERGEX is concerned with the restriction to a one year limit because a high reward arising from STPIS could result in prices exceeding the side constraint.

Q. The AER would like views on the proposed mechanism to align the scheme with the EBSS.
ENERGEX is unclear about the alignment with EBSS.
Q. The AER would like views on the proposed timing of the incentive and the impact of requiring all reporting on a calendar year as proposed.
ENERGEX is concerned about the timing of the incentive for those operating on a financial year. The proposed 6 months prior to application of the s-factor effectively provides only 3 months to finalise the data for STPIS (given the process for price approval takes 3 months). While ENERGEX supports calendar year reporting, the practicality of the timing is a concern as outlined above. ENERGEX questions the need for national consistency on calendar year reporting. An alternative would be to align performance reporting to the relevant jurisdictional pricing period. This would enable a 12 month delay in application of the scheme to prices for all DNSPs.
Q. The AER seeks views on the parameters, threshold levels, payment amounts and exclusion criteria in the GSL component of the proposed STPIS.
ENERGEX has an existing GSL scheme in operation. In the event the proposed national scheme was implemented in Queensland, it would need to consider and align parameters, definitions, exclusion criteria and payment amounts.