23 April 2020

Mr Brett Everett
Independent Pricing and Regulatory Tribunal (IPART)
PO Box K35
Haymarket Post Shop, Sydney NSW 1240

Lodged: *via online portal*

Dear Mr Everett

ISSUES PAPER: REVIEW OF DISTRIBUTION RELIABILITY STANDARDS

Endeavour Energy appreciates the opportunity to provide this response to IPART's issues paper. We consider periodic review of the reliability standards is necessary to ensure they remain fit-for purpose and provide customers with certainty over the level of reliability they should expect to receive from licence holders.

As per the scope of this review, we understand IPART is reviewing reliability standards and considering new technologies with the objective of improving energy affordability for NSW customers. There may be a concern that NSW networks provide a higher level of overall reliability than required by the standards and customers may be willing to accept lower levels of reliability in return for bill reductions. Broadly, our position is as follows:

1. Energy affordability remains a key focus and we have taken significant steps to reduce our contribution to customers' bills over the last decade. Any additional measures that are introduced to put downward pressure on electricity prices should not have any unintended consequences or distort the economic regulatory framework. Compliance with reliability standards should continue to drive only a small proportion of our total investment program.
2. Jurisdictional standards play an important role in guaranteeing customers a minimum level of service quality. Given the inherent difficulties in accurately determining the optimal cost-service mix we consider ex-ante incentive regulation is the best means by which to reveal the efficient amount of network costs and average level of service quality.
3. Emergent technologies will best serve customers if they are introduced through cost-reflective and equitable price signals and competitive markets. Networks will be a key source of innovation and demand for these services as an alternative to traditional investment solutions.

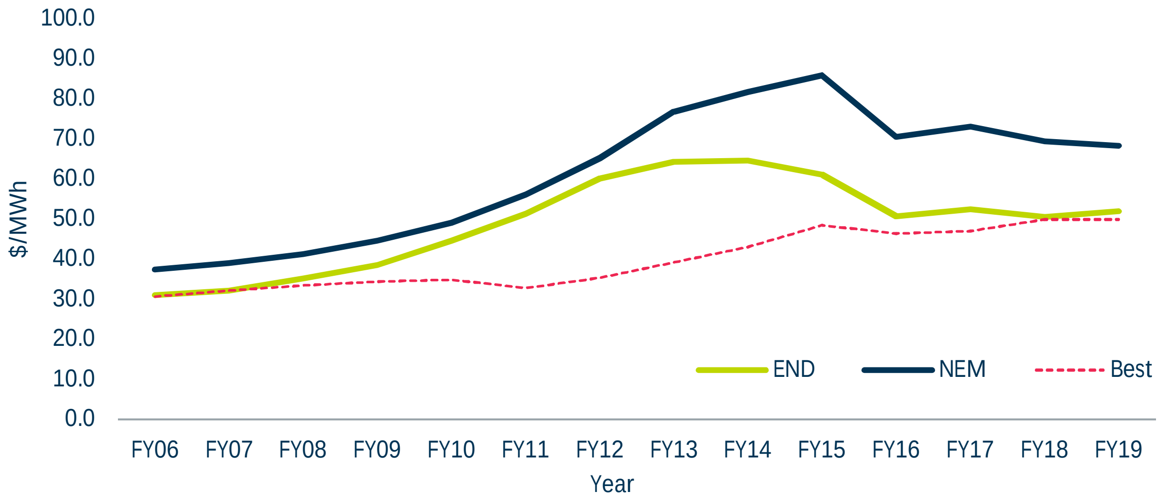
Endeavour Energy has taken steps to improve energy affordability

With respect to energy affordability we understand through our engagement with customers that this is their number one concern and priority. This has become increasingly apparent as customers have acutely felt the pricing impacts of the 2009-14 capital investment peak associated with the Schedule 1 design and planning licence conditions.

The removal of these licence conditions was one factor that contributed to a 45% reduction in our capital expenditure in the 2014-19 regulatory control period (compared to 2009-14) and we expect to maintain this reduction over the 2019-24 period. Similarly, we have made significant reductions to our operating expenditure which has materially improved our operating efficiency. Against the AER's benchmarking measures Endeavour Energy's MTFP ranking has improved from 9th to 6th in recent years, driven by our opex MPFP performance which ranks 5th in the NEM.

These efforts have meant that Endeavour Energy has not had any real increase in its contribution to electricity bills in a decade moving our network price to amongst the lowest in the NEM.

Figure 1. Average price per MWh delivered



Recent capex and opex reductions have been made while marginally improving our reliability performance. Our 2019-24 determination will see a continuation of this performance by locking in further reductions in prices, opex per customer and RAB per customer.[1]

Efficient outcomes are best achieved through the NER framework

The NSW reliability standards have provided an effective safeguard for customers, particularly for those connected to less resilient parts of the network. We recognise the existing standards were not developed with reference to the value customers place on reliability and support IPART applying economic cost-benefit analysis to guide the review.

Whilst the outcomes of IPART's economic assessment could provide valuable insights on the cost and value of different reliability levels, it is important that any recommended changes to the standards continue to complement rather than duplicate or undermine other aspects of the economic regulatory framework that govern the services provided by distribution networks.

Specifically, the AER's investment planning framework (e.g. RIT-D, DAPR); incentive schemes; and regulatory determination process work in combination to ensure efficient network investment and reliability outcomes. Demonstrating the customer value of proposed investments is a core requirement of the regulatory framework which has proven effective in encouraging the NSW DNSPs to reduce expenditure and lower network prices whilst maintaining a generally consistent level of reliability in accordance with the preferences of customers.

Prescribing stringent or granular reliability requirements in the licence conditions could risk distorting the balanced incentives that encourage networks to deliver the efficient combination of cost and service outcomes. The marked improvement in the efficiency of NSW DNSPs since the removal of the deterministic reliability and performance standards and overall customer satisfaction with reliability levels support the case for retaining the existing reliability regime.

In the absence of a clear deficiency with the NER framework, we consider reliability standards should continue to set minimum levels of reliability for each feeder category and efficient levels of service quality incentivised through the STPIS which, as highlighted by the ENA[2], has proven highly beneficial to customers and effective in deterring networks from making efficiency gains at the expense of reliability performance.

---

[1] In FY19 $ terms

[2] ENA, Rewarding performance: How customers benefit from incentive-based regulation, July 2019, p. 12. Available from: https://www.energynetworks.com.au/resources/reports/rewarding-performance-how-customers-benefit-from-incentive-based-regulation/

Standards should facilitate new technology and two-way energy flows where possible

Once the AEMC makes final rules to give effect to the new DNSP-led SAPS framework IPART will need to consider what protections should apply to SAPS customers and how these should be reflected in the licence conditions, recognising none of the current feeder categories would be applicable for SAPS supply. Reliability standards should be set to ensure no SAPS customer is worse off than they were when connected to the grid and the licence should provide clarity where the expectations towards supplying SAPS customers differ from standard supply or the national SAPS framework. It will also be important to minimise delays in opting into the framework to ensure NSW networks are able to utilise SAPS where it is the most efficient option.

In relation to two-way energy flows, the current standards do not require networks to cater for the increasing value customers are placing on access to the network for DER exports. Hosting rising DER levels present technical and operational challenges, but the regulatory framework provides little incentive for DNSPs to invest in measures to reduce export constraints and maintain or improve power quality. Whilst the industry is still considering the technical, regulatory and market requirements to optimise the integration of DER into the system, determining a methodology for valuing DER exports remains critical to enabling equitable and efficient network access.

Although mandating network capacity improvements through the licence would improve DER access, this could impose significant cost increases on all customers. It would be more prudent to instead monitor ongoing industry forums such as the DEIP joint initiative, which is considering an efficient Future Grid transition path, and any ensuing rule changes before considering or introducing any mandatory access requirements in licence conditions.

Our views on key issues raised in the issues paper are detailed in Part A of this response and answers to the targeted questions in the issues paper provided in Part B. If you have any queries or wish to discuss our submission further please contact Jon Hocking, Manager Network Regulation at Endeavour Energy on [redacted] or via email at jon.hocking@endeavourenergy.com.au.

Yours sincerely

[redacted]

Deputy Chief Executive Officer

Part A - General Comments

The NER and incentive regulation delivers efficient price and service outcomes

Supply reliability in NEM distribution networks is generally regulated in two ways: through reliability conditions specified in jurisdictional licences and the NER where the STPIS incentivises DNSPs to maintain reliability levels and only make improvements where customers are willing to pay for them. As stated in the NER, the STPIS operates concurrently with any average or minimum service standards and GSL schemes that apply to DNSPs under jurisdictional electricity legislation.[3]

In the NSW licences, minimum SAIDI and SAIFI levels are set for the overall network average (Schedule 2) and for individual feeders (Schedule 3). In both cases, targets have not been set with regard to the value customers place on having continuous supply or vary with actual reliability performance.

This is in contrast to STPIS where SAIDI and SAIFI targets for each feeder category are based on average actual reliability levels over the previous five years. The scheme financially rewards(penalises) networks when actual performance is better(worse) than the targets with the AER's VCR estimates used as an input to calculate the incentive rates which determines the amount of the reward or penalty. This ensures payments are commensurate with the value customers place on the improvement or reduction in reliability.

The overall reliability framework has generally resulted in networks delivering reliability at levels above the minimum standards and more consistent with the STPIS targets. The balanced, counter-veiling incentives within the NER's incentive-based framework has ensured that cost reductions have not been achieved at the expense of reliability. Our customers have indicated general satisfaction with current reliability levels and an unwillingness to trade reductions for lower prices.

In response to this feedback, we (like many other NEM networks) have sought to maintain reliability levels. Whilst there is variation in annual results there has been a gradually improving trend in our reliability performance over recent years. We consider the improvement over the 2014-19 period reflected the lagged impacts of 2009-14 investment peak and significant growth in our customer base and as a result the proportion of underground network. Whilst financial rewards (limited to 2.5% of annual allowed revenue) have been accrued from this improvement, more stringent STPIS targets have been set for the 2019-24 period. This increases the likelihood of underperformance and penalties that would more than offset previous rewards due to the increase of revenue at risk to 5% which notably was supported by the AER's Consumer Challenge Panel.[4]

We note the analysis conducted by the ENA demonstrating the significant customer benefit delivered by the STPIS and incentive regulation more broadly[5] and the AEMC's conclusion that incentive regulation remains the appropriate fundamental principle of the regulatory framework for electricity networks and provides sufficient flexibility to support the evolving role of NSPs.[6]

Whilst the benefits of incentive regulation is widely acknowledged, these findings help to confirm that the incentive schemes which underpin the framework drive beneficial service and price outcomes for customers. The effectiveness of the incentive framework stems from the strength and balance of the incentives for networks to make cost-effective investment and operational decisions. If this is distorted through duplicative or competing reliability standards (i.e. jurisdictional licence requirements to deliver a level of reliability that results in expenditure that differs from efficient levels derived through the economic regulatory framework in the NER) it would detract from the allocative and dynamic efficiency of the framework.

---

[3] NER cl. 6.2.2(b)
[4] CCP10, Response to preliminary framework and approach for NSW DNSPs, April 2017, p. 17.
[5] ENA, Rewarding performance: How customers benefit from incentive-based regulation, July 2019, p. 11
[6] AEMC, Economic regulatory frameworks review – Final report, July 2018, p. i

In short, we believe that the incentive-based framework has been effective in encouraging networks to deliver an efficient price-reliability mix. The expenditure reductions and reliability performance of the NSW DNSPs indicate they are responding efficiently to the incentive schemes underpinning the framework. The discrepancy between reliability standards and actual reliability does not indicate a deficiency in the overall reliability framework that requires a re-design of the standards but rather is a consequence of the networks' attempts to efficiently satisfy the reliability preferences of customers and the licence setting minimum acceptable standards for network reliability.

Relaxing the existing standards will not deliver material price reductions for customers

In accordance with the terms of reference, the purpose of IPART's review is to consider changes to existing reliability standards that could deliver bill savings to customers. Generally, lowering standards would reduce compliance costs and lower network prices.

As the issues paper highlights, the NSW DNSPs typically report network average SAIDI and SAIFI at levels better than required by the licence conditions. Relaxing these standards would not affect reliability compliance investment which is generally targeted to achieve compliance with the individual feeder standards and represents a relatively small proportion of total capital expenditure.

In our case, we plan to spend $20m (or 1% of total capex) over 2019-24 to ensure customers connected to the worst-performing parts of the network receive at least the minimum specified levels of reliability. This is consistent with reliability compliance expenditure incurred during the 2014-19 period and if reduced, would not materially reduce the revenue we recover from customers. This suggests the scope to achieve price reductions by changing the existing levels of reliability is limited and would have an adverse impact on the poorest served customers who are the main beneficiaries of this targeted reliability investment.

Reliability performance standards are more appropriate than planning standards

IPART's economic assessment will involve applying their optimisation model to yield a value of expected unserved energy for a specific component or area of the network. This MWh estimate could be introduced into the licence conditions as a planning standard or alternatively converted into a more conventional reliability measure (e.g. minutes per customer) to set a performance standard.

Performance standards currently apply to each NSW DNSP requiring them to deliver outcomes that at least meet the SAIDI and SAIFI levels specified in their respective licences. Expressed as a planning standard, distribution networks would need to build the network to specified criteria with compliance assessed by reference to a network's planning framework and decision making.

The choice between planning and performance standards was considered during IPART's transmission reliability review in 2016. Performance standards were found to offer advantages such as simplicity, compliance cost and providing reliability certainty to customers. However, the review acknowledged the Productivity Commission's (PC) finding that in contrast to distribution networks it was not possible to rely on output measures as leading indicators of the reliability of transmission networks.[7] Similarly, the AEMC considered measures relating to the capability of network elements are more appropriate for transmission reliability standards.[8]

Ultimately, IPART elected to introduce new planning standards that require TransGrid to plan for a specific level of unserved energy at each bulk supply point (expressed as a maximum minutes per year allowance) and undertake simulation modelling to demonstrate compliance. We agree with the PC and AEMC and consider there are inherent differences between transmission and distribution networks that warrant a different approach to setting reliability standards for DNSPs.

[7] IPART, Electricity transmission reliability standards – Final report, August 2016, p. 20
[8] ibid

Furthermore, introducing planning requirements would signal a partial return to deterministic conditions and restrict the discretion networks currently have in deciding how to satisfy their licence requirements. Preserving this discretion is important as it ensures networks are held exclusively accountable for their investment decisions and for delivering price and reliability outcomes that align with the expectations of customers. In our view, any new licence requirements should be expressed as a performance standard rather than a planning standard.

Feeder categories are the most appropriate way to segment the network for reliability

The NSW DNSPs currently report reliability performance at each of four possible feeder types (CBD, urban, short-rural, long-rural).[9] Reliability varies across each of these categories due mainly to the physical structure of the network and surrounding environment. Definitions in the licence determine how feeders are assigned to these categories so that customers for whom the cost of supply and value of reliability are similar are grouped together. The STPIS adopts the same feeder classifications.

IPART propose to use their optimisation model to analyse reliability at a more granular level with a preliminary view to treat zone and sub-transmission substations as separate network components. In the transmission reliability standards review, efficient unserved energy values were estimated for each bulk supply point and ultimately incorporated into the standards for TransGrid.

Whilst variations in reliability across the network means it would not be appropriate to only set whole-of-network reliability standards, we do not believe it is feasible to set standards and hold DNSPs accountable for performance at the zone substation or feeder level. Developing standards based on the location of a substation, the route of a feeder or which customers they supply will be challenging due to increasingly dynamic network configuration and the introduction of advanced automation which makes the concept of a 'normal state' less clear. Distribution networks have a more complex configuration than transmission networks with more variables outside the control of DNSPs that can impact reliability in any given location and ability to respond to outages which largely owes to network size and position at the end of the electricity supply chain.

As a result, it can be difficult for DNSPs to control reliability at individual substations and feeders through investment and operational decisions. Although networks generally aim to restore supply as quickly as possible, DNSPs are unable to influence reliability outcomes at specific points of the network to the same extent average reliability levels can be maintained at the network and feeder category level.

Caution should be applied when comparing modelled and actual reliability

Irrespective of the network level which expected unserved energy values are calculated, comparisons against actual reliability performance will be inevitable. Whilst it would be appropriate to expect differences between these equivalent values, we are concerned differences could infer DNSPs have not adopted the most efficient cost-reliability mix and customers would instead value cost savings associated with a lower level of reliability.

It is worth noting that current reliability levels are the result of network investment decisions made over several years. The investment decisions for many aging long-lived assets were likely based on a significantly different set of criteria (e.g. compliance with deterministic standards) than considered by the NSW DNSPs today. The vast majority of network investments made by Endeavour Energy have been based on an economic risk cost quantification since the removal of Schedule 1 from the licence and are not driven by SAIDI and SAIFI standards. In most of these cases investment is based on expected unserved energy and VCR.

[9] CBD standards apply only to Ausgrid. Endeavour Energy has a single long-rural feeder which is exempt from Schedule 2 of the licence.

An example of a planning input that has changed more recently is VCR. IPART has proposed using the AER's newly published VCRs for standard outages in their analysis which for NSW customers are generally lower than AEMO's equivalent estimates. AEMO's VCR estimates have been widely used by networks since 2014 as a proxy of customers' willingness to pay for network and non-network options to inform investment decisions for major projects.

Consequently, using the AER's VCR estimates in the model may understate the value of reliability used to inform previous investment decisions and produce results to suggest inefficient cost-reliability trade-off decisions were made. Where the model may suggest that customers would value a lower level of reliability, this would conflict with customer preference from our customer forums to maintain current reliability levels. Whilst the issues paper specifically highlighted feedback from our 2019-24 regulatory proposal engagement which indicated our customers were not willing to sacrifice reliability for cost savings, in reality this view is also shared by customers in other NEM networks.

Conversely, there could also be instances where modelled efficient reliability is at a higher level than currently experienced by customers. This was observed for some BSPs in the transmission review. If these reliability improvements are reflected in the standards, networks may find it difficult to meet the standards at these locations without material additional investment in reliability.

By relying on VCRs, the model fails to consider qualitative responses and views from a cross-section of a DNSPs customers whose reliability preferences may not be reflected in VCR average estimates. DNSPs are required to demonstrate to the AER how this feedback is reflected in investment plans and IPART should similarly take a more holistic view on the value of maintaining existing reliability than is capable through modelling.

A broader approach was adopted by the Essential Services Commission of South Australia (ESCOSA) in their review of reliability standards for SA Power Networks which like IPART sought to apply economic cost-benefit analysis to define reliability levels that were valued by customers. Rather than relying only on VCRs analysis to assess reliability cost-value scenarios to inform their recommendations, ESCOSA also engaged consultants to conduct a contingent valuation study through customer survey. A survey-based approach was considered to have distinct advantages over VCR analysis in that it is based only on the preferences of SAPN customers; it puts forward scenarios based on real projects and provides insights into how the willingness to pay varies across customer groups.[10]

The survey confirmed that a vast majority of customers were satisfied with reliability with only 12% of respondents expressing dissatisfaction. Furthermore, the study revealed that only one cost-value scenario delivered a net benefit to customers – a 10% reduction in interruption frequency for the 27,000 customers on low reliability feeders delivering a $1.9m net annual benefit. However, this result was not supported when VCR analysis was applied to the same scenario which indicated a net cost of $1.6m.[11] In the absence of a strong net benefit from each method, ESCOSA determined there was no clear economic benefit in setting higher reliability standards.

Given the complexity of the modelling exercise it will be important for networks to have an opportunity to review IPART's model and consider any underlying assumptions in detail. Ultimately, we consider there is a high risk of misspecification error given the difficulty involved in estimating efficient service levels. Hence, our preference for ex-ante regulation which seeks to provide a continuous and incremental incentive to make efficient decisions rather than seeking to define the efficient cost-service mix.

[10] ESCOSA, SA Power Networks reliability standards review – Final decision, January 2019, p.73
[11] ESCOSA, SA Power Networks reliability standards review – Final decision, January 2019, p.16

The review should be cognisant of the NSW DNSPs transition to probabilistic planning

In reviewing the reliability standards, IPART will broadly apply the same approach taken in their transmission reliability standards review. A key objective of the transmission review was to move away from standards that were heavily based on network capability (i.e. deterministic) towards one which better focuses on what customers value and introduce the concept of customer value in TransGrid's decision making process.[12] The resulting changes to the transmission licence require TransGrid to plan to have a small amount of expected unserved energy at each bulk supply point over the long term.

In contrast, the NSW DNSPs are no longer bound by similar deterministic licence conditions and have made the transition to a risk-based (i.e. probabilistic) network planning approach. The value of supply continuity (or cost of no supply) as reflected in VCR estimates is included in project cost-benefit analysis and embedded in network planning and investment decision making processes.

Despite this distinct and clear difference in planning approaches and frameworks, IPART's objectives for the distribution review (as outlined in section 3.2 of the issues paper) are mostly similar to those of the transmission review (outlined in section 2.1 of the final report). Specifically, we believe the objective to assist the distributors in applying risk-based network planning and focusing on what customers value[13] is less pertinent for this review given the transition made by DNSPs.

The current reliability standards were not developed with reference to the value customers place on reliability. However, our probabilistic planning approach and use of VCR and expected unserved energy estimates ensures we explicitly consider the value customers place on the outcomes from a range of feasible investment options (which are tested under different scenarios and sensitivities) to ensure the option that delivers the highest net benefit to customers is undertaken. This supports the efficiency of the reliability levels delivered to customers with their satisfaction confirmed during engagements during the 2019-24 regulatory determination process.

The concept of customer value is well established in our decision-making process to inform the efficient cost-reliability mix. The cost savings delivered and overall satisfaction with reliability levels does not support reflecting the outputs of the optimisation model in the reliability standards in the manner applied for TransGrid which was done for a different purpose. Any change required to our investment planning framework to cater for changes to the reliability requirements in the licence is likely to increase costs and require a transition path to achieve compliance.

STPIS targets could inform reliability standards

An alternative to the existing 'safety net' approach would be setting new minimum SAIDI and SAIFI levels for each feeder type based on average historic performance where customers are satisfied with previous reliability levels. Using the average performance of the previous five years would align the standards with the STPIS targets and remove the risk of alternative standards being set that require networks to deliver a different price-reliability mix than would be derived through the NER framework. This approach using either a five or 10-year averaging period was recommended by ESCOSA for SA Power Networks during 2020-25. ESCOSA also recommended that SA Power Networks be required to apply 'best endeavours' to meet reliability targets and provide reports on their efforts to achieve compliance when performance exceeds a specific reporting threshold.

Given ESCOSA also sought to apply economic assessment to inform their reliability standards and considered in detail many of the same issues that are within the scope of IPART's review, we encourage IPART to have regard to ESCOSA's approach and findings when undertaking the review and making recommendations to apply to the NSW DNSPs for 2024-29.[14]

---

[12] IPART, Electricity transmission reliability review, August 2016, p 10
[13] IPART, Review of the distribution reliability standards, March 2020, p 19
[14] ESCOSA, SA Power Networks reliability standards review – Final decision, January 2019, p. v

Whilst we are supportive of this alignment between the standards and STPIS (in lieu of retaining the existing minimum performance levels), we note that IPART has indicated they may consider not including overall reliability standard measures if their modelled efficient SAIDI and SAIFI values are similar to the levels in the STPIS. We consider there is value in retaining overall network standards in the licence as this would explicitly convey IPARTs expectation that licence holders provide an average level of reliability greater than required by the individual feeder standards. This could be particularly important in the context of an evolving market and increasing numbers of customers supplied through parties other than a licensed distributor (e.g. embedded networks; microgrids) should the licence in the future be expanded to cover private network providers to whom the STPIS does not apply.

Part B – Response to the issues paper questions

1. Do you agree that SAIDI and SAIFI measures should continue to be used in the reliability standards, defined in line with the AER's Distribution Reliability Measures Guideline?

Yes. SAIDI and SAIFI are well defined measures that have been consistently reported by all DNSPs over several years and are widely recognised as robust measures of reliability. This is in contrast to expected unserved energy (EUSE) for which there is no readily available historical data at the customer or feeder categories which prevents benchmarking, performance tracking and reliability target setting. SAIDI and SAIFI have a particularly important role in providing a safety net performance level for worst served customers via individual feeder standards.

We support consistency between jurisdictional and national frameworks regarding defining and reporting of reliability performance measures, exclusions and Major Event Day (MED) thresholds. In the case of the latter, the standards should allow networks to use an alternative data transformation method (e.g. Box-Cox method) that provides a more normally distributed data set compared to the natural logarithm transformation under the Beta method (as is permitted under the STPIS).

Consistency should be maintained by requiring any changes to the STPIS or RINs (potentially initiated through a change in the Distribution Reliability Measures Guideline) to also be reflected in the licence and commence at the same time to avoid any complexities and confusion from reporting different values for the same reliability measure. Consistency will benefit customers, networks and regulators and will ensure that the efforts of the NSW DNSPs to provide accurate and timely information is not hindered by differing reporting requirements that require additional (but avoidable) effort and resources to achieve compliance.

2. Do you agree that we should convert our estimate of the efficient level of expected unserved energy to allowances for the duration and frequency of interruptions? How could we convert the efficient level of expected unserved energy to allowances for the duration and frequency of interruptions?

Yes. Our reliability performance history data is recorded in terms of duration and frequency making it easier to monitor compliance. Notwithstanding our concerns about IPART's approach and the integration of modelled reliability outputs in the standards as outlined in Part A, we believe it would be practical to convert results into SAIDI and SAIFI noting the STPIS has a methodology to convert energy into SAIDI and SAIFI measures.

3. Do you agree that the excluded events in the distributor's licences should be consistent with the AER's Distribution Reliability Measures Guideline and Service Target Performance Incentive Scheme? Are there any additional events that should be excluded by the licence or any events that should not be excluded?

Yes. For SAIDI and SAIFI measures to provide a true indication of network reliability it is imperative that the impact of events outside of the control of DNSPs be excluded from performance reporting. Alignment with the AER's Distribution Reliability Measures Guidelines establishes consistency with a national framework that was developed following detailed consultation with industry stakeholders including the NSW networks and made in conjunction with refinements to the STPIS.

4. If there is a risk that the frequency of severe weather events will increase, how should the costs of providing a resilient network and the value customers place on this resilience be balanced and what requirements should be placed in the distributors' licences?

Increases in the frequency of severe weather events will challenge the capability of our network to provide a continuous supply. The severity of these weather events is also increasing as observed with Penrith being reported among the hottest places on earth for brief periods during two of the last three summers.[15] Heat waves drive up demand from our network where equipment ratings are normally calculated on a 40ºC ambient temperature. Our demand forecasts are normalised to 50% POE which means these increasingly common and extreme events are largely ignored in current planning analysis.

To our understanding, the AER's VCR review and estimates do not reflect customer expectations or willingness to pay for a more resilient network that is able to withstand outages from severe weather or bushfire events, although we consider there is a higher customer tolerance of delayed network response during these times. A separate study may be needed to determine the value of network resilience during these periods to inform such standards.

5. Do you agree that payments under customer service standards should reflect the cost to a customer of an outage? How would this best be measured or estimated?

Yes. VCRs could be used as the basis to estimate payments, however the averaged nature of the AER's VCR estimates means they may not always reflect the cost of the outage to the affected customer. To ensure customer service payments do not under/over compensate customers, the variation in a customer's willingness to pay to avoid outages of different durations and frequencies needs to be considered.

For instance, the AER highlighted that most large business customers who participated in the VCR surveys "indicated costs growing at a slower rate the longer the outage persisted, suggesting that after accounting for the initial fixed costs of an outage, costs incurred for lost production are more limited. This results in lower VCRs the longer the outage duration".[16]

6. Should payments under customer service standards increase as the duration (or frequency) of an outage (or outages) increases? Should payments be automatic or continue to require application by a customer? If payments become automatic, should exclusions be based on the major event day measurement that currently applies to the other reliability standards or continue to be defined causally (i.e., with reference to extreme or severe weather as defined by the Bureau of Meteorology).

It is reasonable for payments to increase with higher duration and/or frequency of unplanned outages however, payments would need to reflect customers' falling marginal costs during an interruption which may support the case for a payment cap. Payments should not apply for outages during MEDs (as per the AER's definition) as networks ability restore supply in the usual timeframes is typically severely restricted. It would be uneconomic for networks to provide the same level of response as a standard day and as networks cannot guarantee supply, the threshold for customer payments should be set a level that only represents unacceptable interruption duration or frequency.

Automatic payments will put upward pressure on costs and may fail to take into account whether a customer is present at a premise during an outage and risks overestimating the degree customers are inconvenienced by the interruption. Requiring customers to submit an application avoids payments made for supply loss to vacant premises.

[15] The BOM recorded maximum temperatures in Penrith of 47.3°C on 7 January 2018 and 49.8°C on 4 January 2020.

[16] AER, Value of Customer Reliability – Final decision, December 2019, p. 65.

7. How should reliability standards cater for new technologies such as Stand-alone Power Systems?

SAPS can improve the reliability on poor performing feeders where customers are disproportionately worse off than the average network customer. To measure the extent to which SAPS improves reliability, we believe there is merit in requiring DNSPs to report the reliability performance of each DNSP provided SAPS. SAPS performance should be excluded from feeder category reporting and would require new SAPS specific reliability standards set at levels no lower than the current feeder categories.

More broadly, it might be appropriate to consider excluding from SAIDI and SAIFI calculations customers with batteries who are able to (at least partially) supply their home on the basis they experience no or limited inconvenience from a network supply interruption.

8. Should network reliability standards take account of two-way energy flows and the ability of the network to allow customers to both buy and sell electricity? If yes, should reliability standards take into account the value to customers of being able to export or sell power to the grid? What might this look like in practice?

There is considerable amount of work being done across the industry to consider how best to integrate DER in to the energy system and transition to a two-sided market. A key aspect of the current DEIP initiative is the development of a methodology for determining the value of DER which networks can use to support DER enablement investment decisions.

Until further progress is made in these forums to determine the technical, regulatory and market requirements needed to enable customers to optimise the use of their DER, it may be premature for the licence to introduce obligations around network access for DER exports. Although mandating network capacity improvements through the licence would improve DER access, this could impose significant cost increases on all customers.

Furthermore, clause 6.1.4 of the NER means costs to satisfy licence conditions designed to increase the benefits to customers from DER exports would be shared equally by all customers rather than only paid by those who benefit most from this investment. As customers can only be charged for energy delivered from the network, DER owners would effectively be provided a free service.

Instead, optimising the use of the existing network through cost-reflective pricing signals with limited network augmentation is likely to deliver the most efficient network access outcomes. Our preference is for the current DER-related consultations to guide nationally consistent frameworks that jurisdictions can have regard to when determining state-based regulations.

9. Do you agree with our proposed approach to estimating the efficient level of reliability and basing the standard on the level that delivers the lowest social cost?

Generally, no, for the reasons explained in Part A. Our main concern is that reliability standards based on modelled estimates on the social cost of reliability levels will distort incentives for networks to make efficient investment and operational decisions. The STPIS naturally determines an efficient willingness to spend cap for networks to base their decisions and a jurisdictional determination of efficient unserved energy levels (translated to SAIDI and SAIFI) that is detached from the national incentive-based regulatory framework only risks increasing network expenditure.

The STPIS incentivises efficient and sustainable investment for reliability. In contrast to common belief, it focusses not only on overall performance but also poor performing feeders. We have observed a strong correlation between high STPIS penalty feeders and feeders non-compliant with licence standards.

To a lesser extent the STPIS also incentivises networks to focus on meeting individual customer standards. However, non-compliance typically occurs in remote locations on the network where corrective investment to improve reliability to individual customers can be difficult to justify on an economic basis (although this may improve as SAPS becomes a viable option to DNSPs).

In our view, the review should focus on providing a 'safety net' level of reliability to these individual customers for whom the STPIS provides limited protection. With the AER now requiring DNSPs to include information on their worst served (inadequately served) customers in Annual Reporting RINs from FY20, there may be an opportunity to leverage from this data for state-based safety net considerations.

10. How should we estimate expected unserved energy across distributors' networks (for example by area, substation and/or feeders)?

Analysis of the costs and values of different reliability levels at granular levels of the network will require significant amounts of data and time and on the whole will be a resource intensive exercise which we are not convinced is warranted for the purpose of setting reliability standards. In reality, analysis of the detail and type contemplated by IPART is only undertaken where there is a known constraint on the network. We consider attempts to derive efficient reliability at zone substation or feeder levels through the optimisation model risks returning inaccurate values that are not truly representative of the capabilities of the network or our prudent approach towards managing a safe and reliable network.

The difficulty of determining meaningful efficient levels of unserved energy in different parts of the network will be particularly challenging given the evolution and dynamic changes within distribution networks. In the future there may be a range of situations that may fall within the concept of 'normal state', each with different operational characteristics.

An alternative to analysing efficient reliability levels at different parts of the network would be to evaluate reliability on the basis of customer type. Whilst it may require some additional data on customer activities, a standard average energy consumption per customer type or grouping would be preferred over the proposed network component approach.

11. Do you agree with our proposed approach to estimating the following inputs:

- **the cost of expected unserved energy, which is a result of:**
  - **the value customers place on reliability (VCR)**
  - **the probability of asset failures**
  - **the duration of outages and restoration profile**
  - **profile of demand at each location**
  - **number and capacity of transformers and feeders and/or non-network options**
- **the direct costs (operating and capital costs) of providing different levels of reliability, and**
- **a discount rate and asset lives to convert capital costs to an annuity.**

To derive meaningful results, the optimisation model will need to be adapted to account for the topology of each distribution network which as previously stated are inherently more complex than transmission networks. It will need to be configured to reflect the design of the network whilst also being cognisant of the way in which we operate and manage the network to minimise the impacts of interruptions on customers. We believe this will be a highly complicated task and may require data beyond what is reported through the AER's RINs.

For instance, modelling the restoration profile for the everyday practice of partial restorations post fault would be extraordinarily complex and difficult to glean through RIN data. However, that practice is probably the single biggest action networks take to maximise reliability performance.

We understand TransGrid spent many months deriving data (e.g. failure rates; restoration/repair times) to use in the model during the course of the transmission reliability standards review. It would not be practicable for us to provide information of the type or detail needed to run the model for elements across our entire network where these are only derived and used when assessing individual investment projects.

Where data is not available, our standard approach is to use generic assumptions. Given that many of the inputs required to run the model are not reported in the RINs, it may be necessary to apply these assumptions in IPART's analysis. Based on the information collected for the transmission review, potential data gaps include:

- (15 minute) load profile data for every location in order to calculate EUSE. (This is a large volume of data that is not reported in the RIN).
- Customer segmentation by location of the network in order to calculate the correct VCR, (Not reported in RINs and will require effort to calculate).
- Transfer capability at every location. (We use this for EUSE for individual projects, but would require significant effort to determine across the whole network).
- Operating and capital cost by network asset. (Not reported in RINs).
- Unserved energy. (Not reported in RINs meaning any compliance reporting on this measure will be administratively burdensome).

In addition, grouping transformers by location and rating is possible but grouping feeders for the purpose of EUSE is more problematic. The RIN does not readily provide groupings of assets for the purposes of N-1 contingency analysis. Interconnections between sub-transmission substations and bulk supply points provide post contingency switching options from feeders that are not normally part of the 'group'. If these are ignored in a network wide review EUSE will be overestimated, but if included will make the study unwieldy.

We would welcome the opportunity to work through these modelling challenges with IPART during the course of the review and identify opportunities to simplify the model to ensure it can be appropriately applied to distribution networks.

12. What role does including reliability standards in licences play, and do you agree that the standards should minimise any duplication of incentives between the NSW distributor licences and national regulatory framework?

Duplication that distorts the incentives for networks to make efficient investment and operational decisions in the NER framework should be avoided. This is best achieved by the licences maintaining a 'safety net' level of minimum reliability for customers.

Whilst we support maintaining consistency with the STPIS, there could be a case for removing the overall network and (to a lesser extent) individual feeder standards given the STPIS encourages networks to focus on these two areas. However, it is important for the licence to protect worst served customers by continuing to set minimum individual customer standards and require networks to explain the circumstances for each instance of non-compliance.

13. What is the appropriate compliance framework for monitoring performance against distribution network reliability standards? Should IPART have the flexibility to determine the frequency of reporting, in response to performance?

We support a review of the reliability standards every five years to align with each regulatory determination period and consider it appropriate for networks to report performance against the standards to IPART on an annual basis. Although reporting should not introduce significant administrative burden, IPART should have discretion on the level of reporting requirements on licence holders.

Submission Form - Electricity Distribution Reliability Standards

Submission date: 24 April 2020, 11:41AM

Receipt number: 5

Related form version: 2

Question	Response
IPART Submission Form	
Industry	Energy
Review	Electricity Distribution Reliability Standards - 2020
Document Reference	441a637d-105b-486c-97ff-6fa87d69e08d
What elements of reliability are most important to you? For example: • maintaining affordability, • restoring supply after severe weather events, and/or • the ability to export solar to the network.:	
Do the current standards provide appropriate incentives for the distributors to restore supply during long and widespread unplanned outages?	
What level of financial compensation should customers receive when they experience unplanned outages? What types of outages should these apply to? For example only unplanned outages longer than four hours that were not caused by extreme weather.	
If you have attachments you would like to include with your feedback, please attach them below.	Endeavour Energy response (final) - Review of distribution reliability standards issues paper.pdf
Your Details	
Are you an individual or organisation?	Organisation
If you would like your submission or your name to remain confidential please indicate below.	Publish - my submission and name can be published (not contact details or email address) on the IPART website
First Name	Joe
Last Name	Romiti
Organisation Name	Endeavour Energy
Position	Regulatory Analyst
Email	joseph.romiti@endeavourenergy.com.au
IPART's Submission Policy	I have read & accept IPART's Submission Policy