Ausgrid Submission

IPART Reliability Standards Review

January 2021

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25 January 2021

Attn: Fiona Towers
Independent Pricing and Regulatory Tribunal
2-24 Rawson Place
HAYMARKET NSW 2000

Dear Mr. Everett

Ausgrid is pleased to provide this submission on the Independent Pricing and Regulatory Tribunal's (**IPART**) Draft Report (**Draft Report**) on the review of NSW electricity distribution reliability standards.

It is important that the NSW reliability standards remain fit-for-purpose in the context of rapidly changing energy markets. We therefore welcome IPART's review and its collaborative approach to engagement to date.

Under the terms of reference, the intent of the review is to identify potential bill savings for NSW electricity customers through an economic assessment of the electricity distribution reliability standards. Keeping this in mind, our submission makes the following key points:

- **In recent years Ausgrid has delivered significant bill savings for customers**

  Since reliability standards were last updated, Ausgrid has made significant steps towards improving both the affordability and reliability of the network. Since 2014 our annual network charges have reduced by $226 for the average residential customer in our network area, while our reliability has remained in line with our customers' expectations. This demonstrates that the current regulatory regime is delivering positive outcomes for customers.

- **The draft reliability standards may put upward pressure on our costs and therefore bills**

  In the Draft Report, IPART has estimated the 'existing' and 'efficient' annualised cost of operating each of the NSW distribution networks. Given the complexity of this analysis and constraints to its practical application, there is a risk that these estimates could be misinterpreted and/or inappropriately used in a context for which they were not intended.

  IPART's modelled values for 'existing' and 'efficient' costs are based on the adoption of the 'efficient' technology and configuration for the whole of Ausgrid's network. The reality in an established network such as Ausgrid's is that there would be a slow migration to the new configuration through asset replacement programs over many decades (at an asset replacement rate of 1-2% per annum). Therefore, reliance on the difference between 'existing' and 'efficient' as quoted in the Draft Report, without further qualification, overstates the extent of any possible gains under such a model.

Further, we spend only about $1.8 million p.a. on 'remedial' investment programs targeted at complying with our existing reliability standards. This relatively low level of capital expenditure (**capex**) indicates that there is little scope for bill savings to be delivered through changes to the reliability standards in the NSW Licence Conditions. There is in fact a risk that system changes and added complexity in regulatory reporting could increase our costs.

- **Customer bills could be higher under the 'refund model' for long or frequent outages**

  IPART is proposing that the compensation for customers who receive long or frequent outages should be based on a 'refund model'. If implemented, this would mean that a very small subset of customers (~1%) would pay heavily discounted or no distribution network charges, whilst other customers would, on average, have higher bills. We estimate that the total cost of the changes could be as high as $6.4 million per annum (see section 2.1 below).

- **Additional costs in reporting against some distributed energy resources (DER) measures**

  We currently have limited visibility of our low voltage (LV) network, particularly at the point of customer connection. In the past, given the lack of DER and the one-directional flow of electricity across our network, this hasn't been a problem. In the future, however this lack of visibility, is likely to present challenges in complying with some of IPART's proposed DER reporting requirements. To take this into account, some DER measures may need to be removed from the Compliance Manual if it becomes clear, ahead of mandatory reporting in FY25, that reporting against them is not possible or would impose costs that outweigh the benefits to customers. These reporting measures could then be introduced iteratively as we improve our LV network visibility when our internal cost-benefit analysis identifies that it is efficient to do so.

These issues are outlined in further detail below and we would appreciate the opportunity to discuss them with IPART prior to publication of the final report. If you have any questions about our submission, please contact Shannon Moffitt, Regulatory Strategy Manager, on [redacted]

Yours sincerely

[redacted]

Alex McPherson
Head of Regulation

Part 1: Network reliability standards

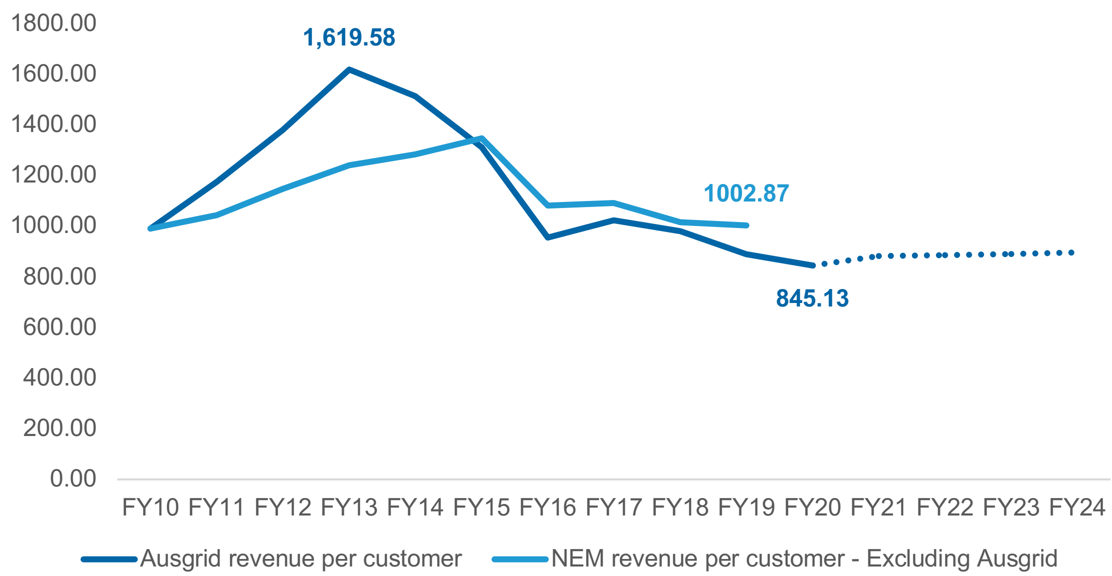
In part 1 of this submission, we address IPART's recommended changes to the NSW electricity distributor's network reliability standards. We make the following key points:

- we are already delivering on affordability, with our annual network charges reducing by $226 for the average residential customer since 2014 and our total expenditure (totex) per customer among the lowest in the national electricity market (NEM);
- as global mean temperatures continue to rise, the resilience of our network to climate change is the most significant threat to meeting customer expectations in terms of reliability and costs.
- the limited purpose and application of the economic model IPART has developed needs to be clearly articulated in the final report.

1.1. Ausgrid is already delivering on affordability

Since our reliability standards were last reviewed, we have made significant progress towards improving affordability. Figure 1 shows our annual revenue per customer has fallen 48% from its peak in FY13, and that while we were once well above our peers on this measure of affordability, we are now below the NEM average.

Figure 1 Annual total revenue per customer ($FY21 real)[1]



1.1.1 Capital and operating expenditure savings

The bill savings unlocked in recent years follow our transition to a more sustainable level of capital expenditure (capex) following the removal of deterministic planning standards in 2014. This is demonstrated in Figure 2 which shows we have moved from an average capex spend of $1,566 million p.a. (FY10 to FY14) to $570 million p.a. (FY20 to FY24).

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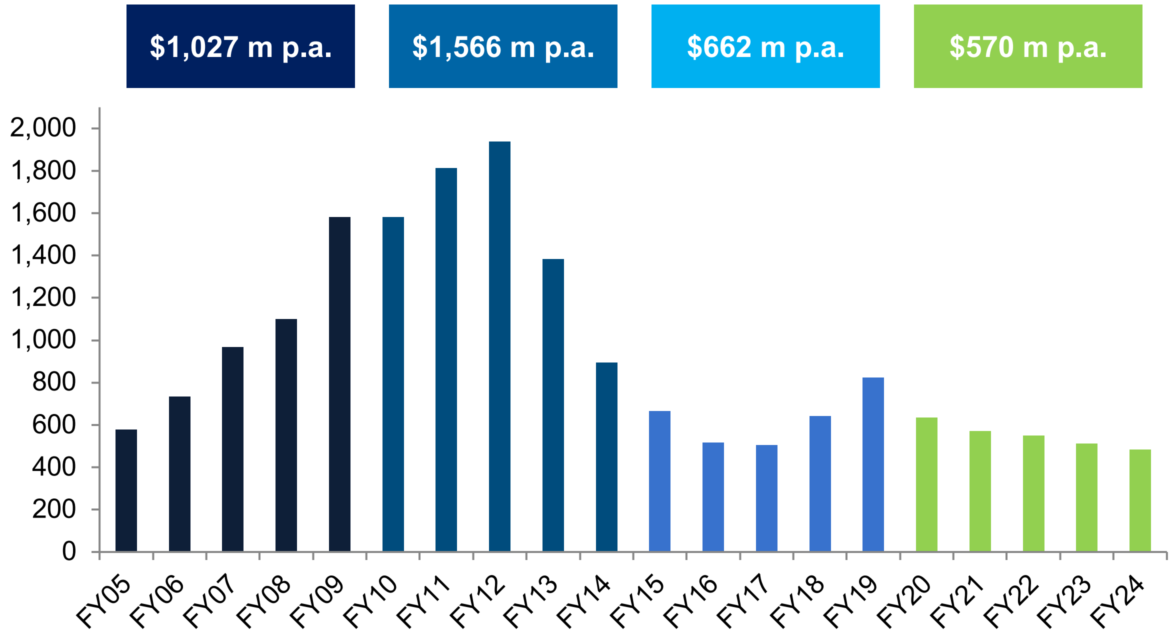
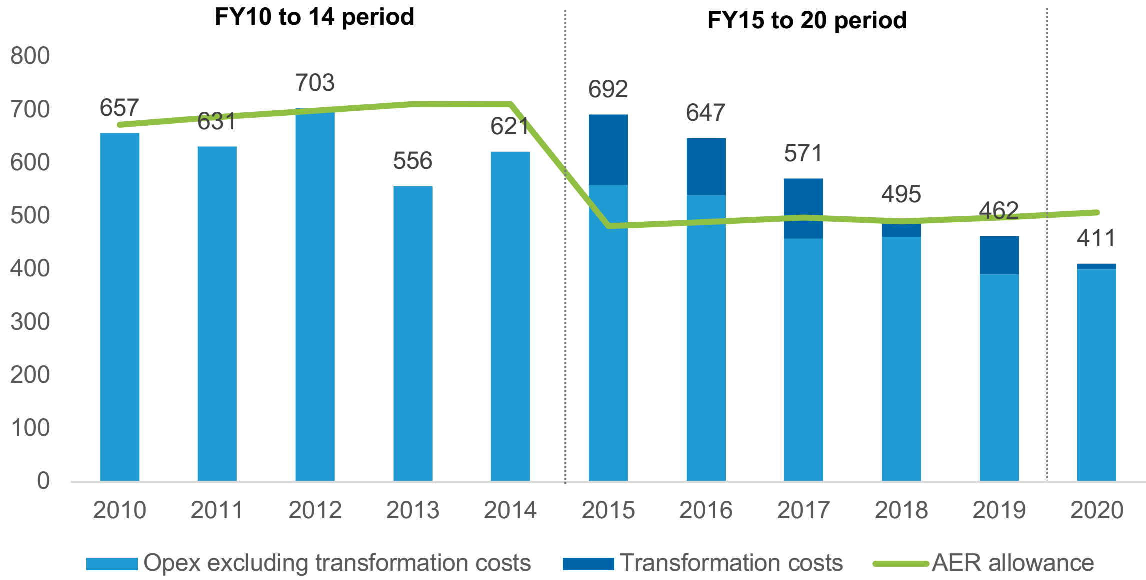
1 AER, Network Performance Report 2020, September 2020.
Note: revenue per customer based on total revenue and all customers (residential, commercial, industrial).

Figure 2 Ausgrid standard control service capex ($real FY21)



At the same time, we have implemented difficult, but important, transformation initiatives targeted at delivering a greater level of operating cost efficiency. We have made substantial progress with this transformation and it continues, as shown in Figure 3 below. In the first year of our current regulatory period (FY20) our opex was $411 million (real FY21), significantly less than the $692 million (real FY21) we incurred five years ago. Past year's opex have included transformation costs that are now leading to a lower operating cost base.

Figure 3 Ausgrid standard control services opex (real FY21)



1.1.2 Our benchmarking performance has improved significantly

In addition to promoting greater affordability, the transformative initiatives we have implemented in recent years have led to the largest growth in productive efficiency among our industry peers. Figure 4 sets this out, showing that since 2015 our total productivity (MTFP)[2] has increased by 3.7% while our [3] productivity (opex MPFP) has grown by 11.5%, more than any other electricity distributor in the National Electricity Market (NEM). Figure 5 shows that Ausgrid now has the second lowest total expenditure (totex) per customer in the industry, at $767 per customer.

Figure 4 Growth in total and opex productivity in the NEM since 2015[4]

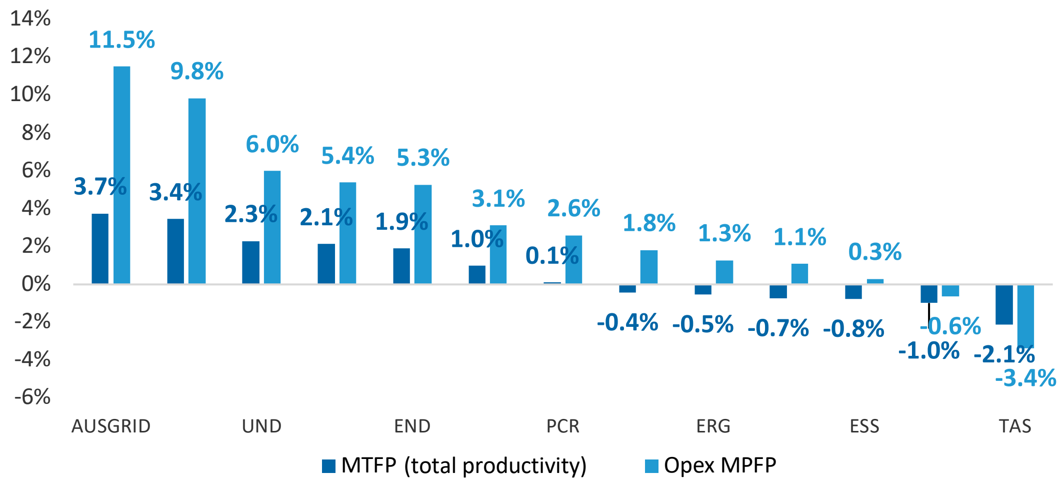
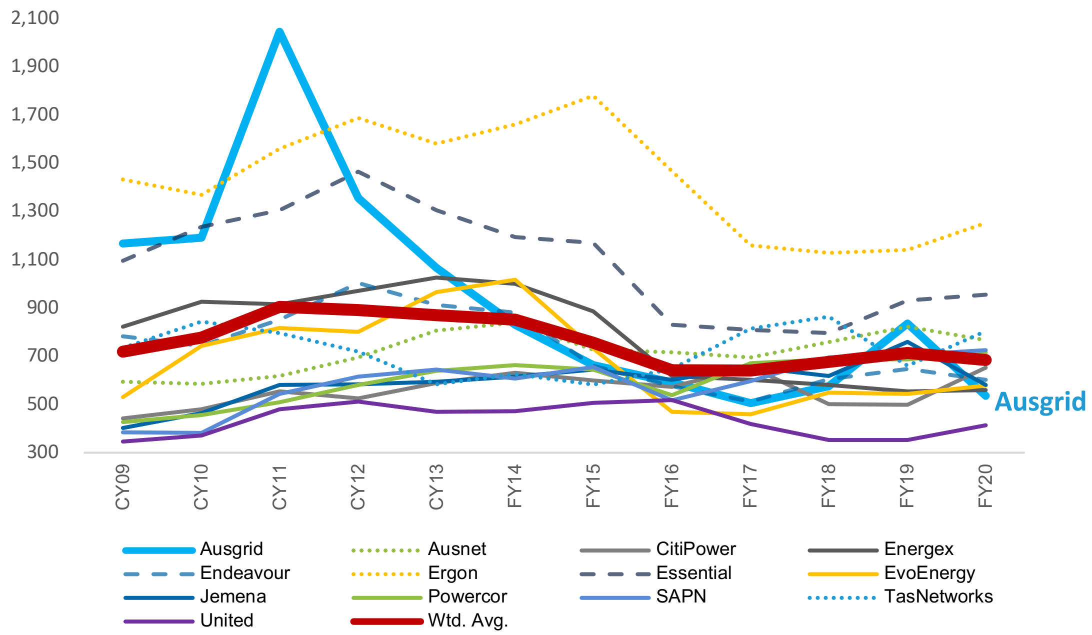


Figure 5 Totex per customer in the national electricity market (real FY21)

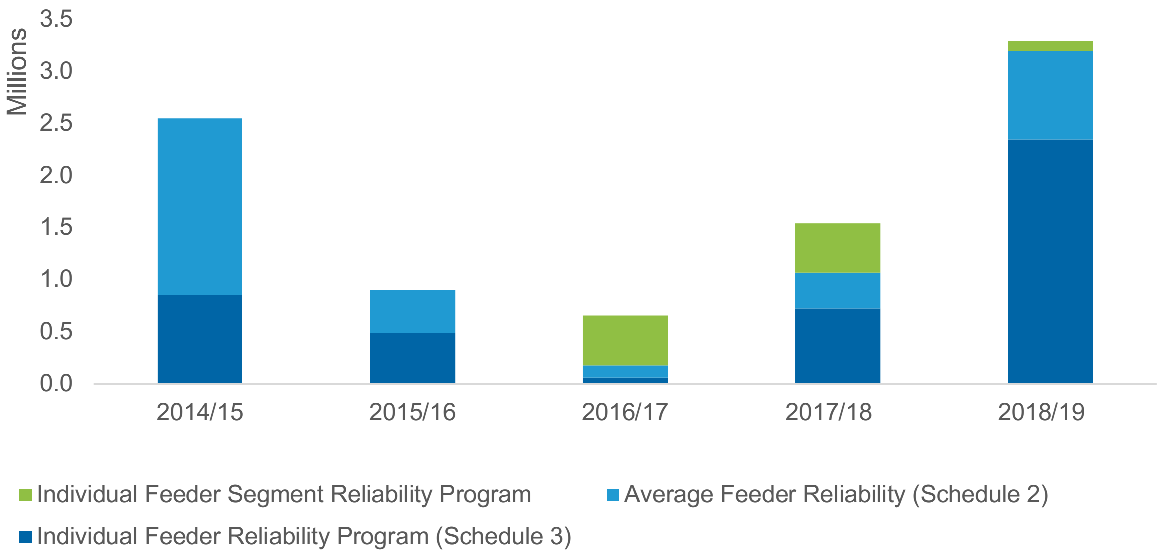


2 Multilateral total factor productivity (MTFP)
3 Opex multilateral partial factor productivity
4 AER, 2020 benchmarking report, MPFP efficiency scores, November 2020

1.1.3 Only small levels of investment needed to comply with current standards

Our level of investment targeted at complying with the current reliability standards in our Licence Conditions is relatively small. Figure 6 shows that in the past five years the maximum we have spent is $3.3 million while, on average, it has averaged about $1.8 million per year since FY15, or only 0.3% of our annual average capex program over this period.

Figure 6 Actual capex to comply with our existing reliability standards ($nom)



Note: The 'individual feeder segment reliability program' captures the cost of remediating performance in between protection devices (e.g. downstream from a recloser). The 'average feeder reliability' and 'individual feeder reliability' capex is driven by compliance with the average (Schedule 2) and individual (Schedule 3) feeder reliability standards in our Licence Conditions.

The low level of investment is driven by the removal of deterministic planning standards. This has meant that non-compliance with our current reliability standards, rather than driving investment, usually only triggers an investigation. This is important context which should be included in the final report so that policy makers can appropriately calibrate any changes to our Licence Conditions.

Recommendation 1:

The final report should include additional commentary about the cost reductions that have already been made since the NSW electricity distributor's Licence Conditions were last reviewed. This will provide important context to the recommendations that IPART is required to make under its terms of reference.

Recommendation 2:

The final report should include information on the current level of capex Ausgrid spends on complying with our reliability standards. This will assist policy makers to calibrate their response in a way that ensures any changes to our Licence Conditions are proportionate to the issues at hand and the magnitude of the costs that are involved.

1.2. IPART's modelling of Ausgrid's annualised costs

IPART has estimated the 'existing' and 'efficient' annualised cost of running each of the NSW distribution networks.[5] The 'efficient' costs are based on the modelled network philosophy and technology being applied to the whole of Ausgrid's existing network. Given the complexity of this analysis and constraints to its practical application, there is a risk that these modelling results could be misinterpreted and/or inappropriately used in a context for which they were not intended.

In particular, the Draft Report does not sufficiently acknowledge that:

- 'Existing' costs reflect decisions made over a significant period using the most efficient technologies available at the time.
- These existing technologies have inherently long lives of 40-50 years (resulting in low annualised costs), leading to a very slow migration to an 'efficient' network based on the enhanced capability of newer technologies, if asset replacement is used as the mechanism for moving to the 'efficient' network.
- The 'efficient' annualised cost therefore represents a theoretical maximum which is most likely not practically achievable in a brownfield network without significant investment and the potential for stranding of existing serviceable assets which were efficient technologies at the time of investment.
- This theoretically efficient solution will change over time as technology, loads and customer preferences change, meaning that even if a theoretically efficient network was achieved today, it is unlikely to remain that efficient for the life of the investment. This is because as soon as more customers connect to the network and change the load and length of the feeder, the network no longer meets IPART's 'efficient' network design. This happens thousands of times a year and therefore the 'efficient' network design is constantly changing.

The final report should acknowledge the above points as well as clarifying that IPART's modelling has been developed for a specific purpose, set out in the terms of reference. The final report should also more clearly note appropriate limitations to the use of the modelling results so that stakeholders do not attempt to apply the results to other situations for which they were not designed

Areas which require additional commentary and explanation are outlined further below.

1.2.1 Exogenous factors need to be more clearly acknowledged

There are exogenous factors which have a significant impact on the 'existing' annualised network costs of the NSW electricity distributors. These should be explained in greater detail in the final report, particularly when comparing 'existing' and 'efficient' costs.

<u>Differences in costs driven by technology</u>

The Draft Report does not account for differences in technology when comparing the 'existing' annualised network costs of the NSW electricity distributors, with the 'efficient' level. To provide transparency, the final report should include additional commentary on the impact of technology changes. In particular, it should be acknowledged that the 'existing' scenario is based on a 'real world' set of circumstances in which a mix of technologies dating back to the 1960s, or even earlier, is employed. IPART should then clarify that the 'efficient' scenario is based on a hypothetical set of circumstances in which the NSW distribution networks were built and configured using only the latest technology that, in reality, was not actually available when assets currently in operation were

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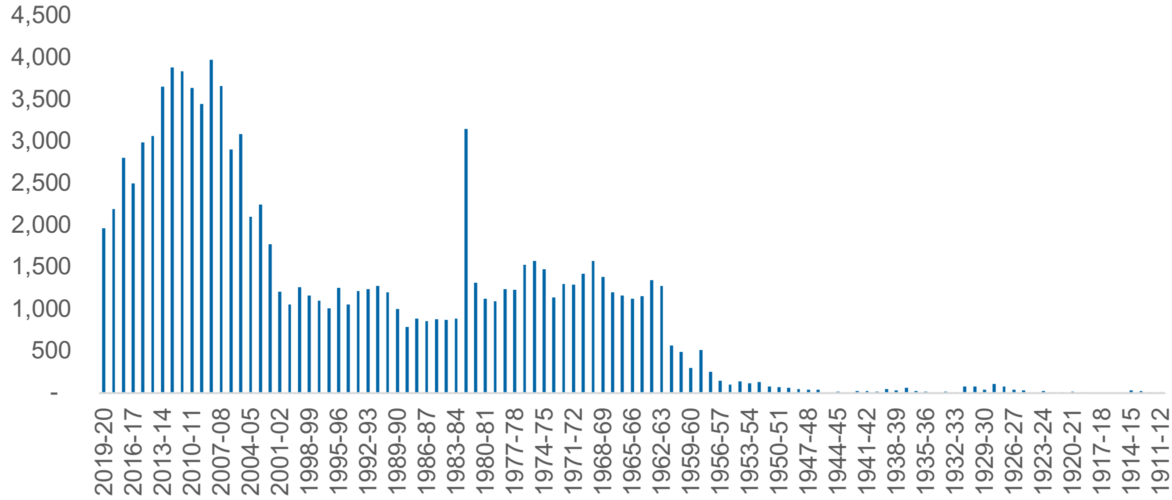
5 IPART, *Review of Distribution Reliability Standard*, October 2020, p. 41-43.

commissioned. This is an important clarification which would help stakeholders understand that technology is a material, exogenous factor impacting IPART's modelling results.

Electricity networks in NSW have evolved over time, as load centres have emerged and expanded in line with population growth and changes in demand. This evolution, coupled with the long technical lives of network assets which generally last up to 40 or 60 years, means that the NSW electricity distribution networks employ a mix of technology ranging from 'brand new' to 'very old'. The technologies employed were the most efficient available at the time and were implemented to deliver the lowest annual cost per annum for a given performance outcome.

To use an example, the age of all <11kV switches on our network is set out in Figure 11. It shows that while some of these assets were installed as recently as FY20, and therefore make use of the latest technology, other <11kV switches on our network date back to the 1960s or even earlier.

Figure 7 Asset age population for <11kV switches



This mix of technology used on our network is an important consideration. When taken into account, it demonstrates that the juxtaposition of the 'existing' and 'efficient' costs in IPART's Draft Report is not a 'like-for-like' comparison. This is because the 'existing' costs are based on a range of assets the NSW electricity distributors have installed over decades, some of which employ technology dating back to the 1960s or earlier, while IPART's calculation of 'efficient' costs is based only on the most advanced technology available today. These technological differences manifest themselves in terms of:

- **Productive efficiency** – newer assets employing the latest technology tend to deliver the same (or more) output for a lower cost compared to older assets; and
- **Network configuration** – how the network is configured is influenced by the available technology. For example, to meet reliability standards when existing assets were installed may have necessitated 'poles and wire' network solutions which today could potentially be avoided or reduced through greater investment in advanced distribution management systems and intelligent network switching.

These technology-based efficiencies were simply not available when the vast majority of 'existing' investment decisions were made. A transition to the technology-enabled 'efficient' network modelled by IPART requires careful consideration to ensure that the intended benefits are not prohibited or outweighed by the cost of stranding previous (efficient at the time) investments.

<u>Length and cost of transition should be acknowledged</u>

The Draft Report states that IPART's economic modelling results can deliver efficiencies if they are taken into account 'when considering capital expenditure associated with replacement'.[6] If replacement is seen as the key opportunity for lower costs, the final report should acknowledge that the legitimately long technical lives of existing network assets will lead to a lengthy transition.

For most asset classes, we replace about 1-2% of the existing fleet each year. If we maintained this replacement rate going forward, it would take 50-100 years for our entire fleet of existing network assets to be renewed and reconfigured in a way that IPART's Draft Report envisages, even if that configuration and technology remained the most efficient approach.

It should also be acknowledged that transitioning to a lower cost network over the long run is likely to lead to additional costs in the short to medium term. We are at a critical juncture in the transformation of the electricity supply chain where investment in intelligent network switching and advanced distribution network systems can empower customers to take control over their energy usage and deliver bill savings.

In our view, IPART should supplement the modelling work it has undertaken with additional commentary about the investments that are likely needed to take advantage of the latest technology and transition to a more flexible, advanced grid that has a lower annualised cost. At the same time, it should be made clear that such investments should only be made when it is efficient to do so, in accordance with the economic cost benefit analysis already employed under a probabilistic planning approach.

1.2.2 We already employ robust cost benefit analysis

Under the terms of reference, the intent of the review is to identify potential bill savings for NSW electricity customers through an economic assessment of the electricity distribution reliability standards. While we agree economic modelling should play an important role in forecasting prudent and efficient expenditure requirements, we consider our internal cost-benefit analysis is already calibrated to achieve this outcome for customers.

Our approach to cost-benefit analysis is summarised in Figure 8 below. It shows that when considering a potential investment, we have regard to multiple risk areas including a monetised value of 'network risk' based on the probabilities associated with a network failure and the consequences of that risk in terms of unserved energy. We also take other risk areas into account including safety, fire, the environment, and financial risks such as penalties. To proceed with an investment, the risk mitigated (the benefit) must exceed the investment cost. This part of our investment governance is set out the cost-benefit equation in Figure 9 below.

6 IPART, *Review of Distribution Reliability Standard*, October 2020, p. 43

Figure 8 Our cost-benefit analysis approach

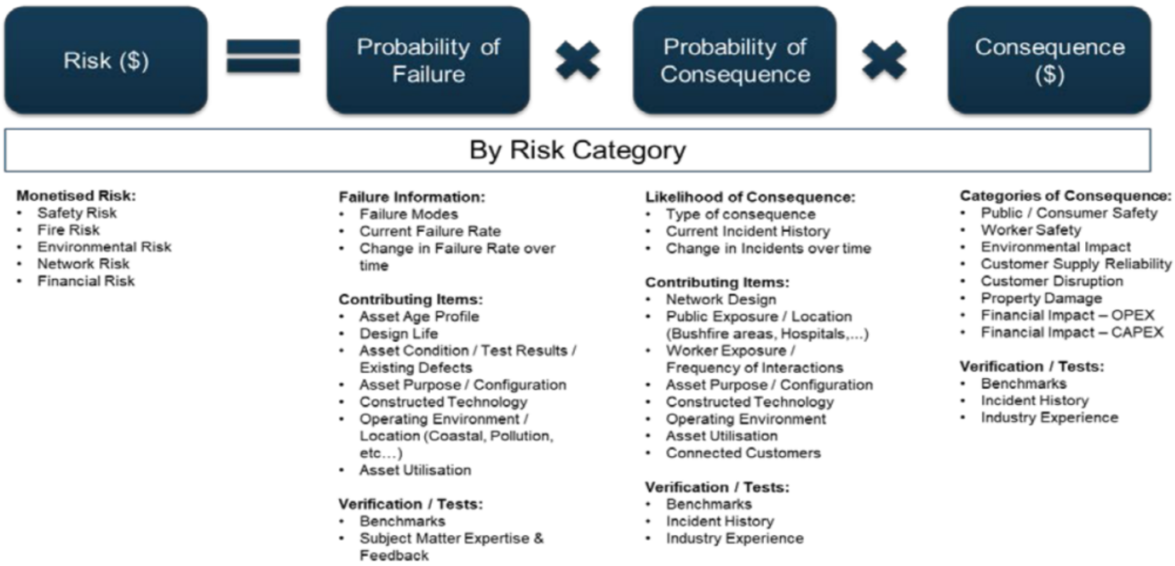


Figure 9 The cost-benefit equation we employ to make investment decisions

Our risk-based approach to network investment aligns to *ISO31000: Risk Management and the AER's Industry Practice Note for Asset Replacement Planning*. Ahead of submitting our 2019-24 regulatory proposal to the AER, we also engaged Frontier Economics to independently assess the economic approach we undertake, who found that the method we use to assess the appropriate timing of replacement investment 'conforms to sound principles of cost benefit analysis'.[7]

Recommendation 3:

The final report should clarify that IPART's modelling results have been developed for a specific purpose, set out in the terms of reference, and that stakeholders should not attempt to apply the modelling results to a situation or context for which IPART's model was not designed.

Recommendation 4:

The final report should include additional commentary on the impact of technology on IPART's modelling of 'efficient' and 'existing' costs. This should clarify that the 'efficient' scenario is based on a hypothetical set of circumstances in which the NSW distribution networks were built and configured using only the latest technology that was not available when most assets currently in operation were commissioned

Recommendation 5:

The final report should acknowledge that transitioning to a lower annualised network costs, as envisaged by IPART's modelling results, would require additional investment in intelligent grid technology and advanced distribution management systems. At the same time, it should be made clear that such investments should only be made when it is efficient to do so, in accordance with the economic cost benefit analysis already employed under a probabilistic planning approach.

Recommendation 6:

Our investment decisions are already calibrated to unlocking efficiency savings for customers and have been independently verified to conform to sound principles of cost benefit analysis. This should be acknowledged in the final report as it is directly relevant to IPART's terms of reference to ensure that there are economic tools in place to identify bill savings.

1.3 Current drafting risks reintroducing elements of deterministic planning

We support the continuation of the existing requirements to monitor, investigate and report on the reliability of individual feeders that do not meet the appropriate standard. We nonetheless have concerns with the current drafting of these arrangements. For ease of reference, we have copied the relevant section of our Licence Conditions in Figure 10 below. Our concern is with clause 5A.3(b)(ii), which is highlighted.

Figure 10 IPART's proposed drafting for report and investigations[7]

5A.3 A *rectification plan* must:

(a) set out:
- (i) the solution(s) selected (unless clause 5A.3(b)(ii) applies such that there is no solution selected) to rectify the cause or causes for exceeding the relevant *individual feeder standard(s)* or *direct connection standard(s);* and
- (ii) the timeframes for completing the steps required to implement the solution(s);

(b) apply the following principles:
- (i) the solution(s) selected must be subject to a cost-benefit analysis and must demonstrate a positive net benefit;
- (ii) the Licence Holder may decide not to select a solution only if there is no solution that demonstrates a positive net benefit following cost-benefit analysis;
- (iii) all reasonable steps to improve conformance with the individual feeder standards or direct connection standards should be taken;
- (iv) the timeframe for rectification should be as short as reasonably practicable;
- (v) implementation of the rectification plan must commence no later than 6 months from the date the investigation report is completed; and
- (vi) solutions identified in condition 5A.2(c) involving a non-network option are preferred where they are equal or more cost-effective than a network option.

In our view, clause 5A.3(b)(ii) above could be interpreted in a way that places a regulatory obligation to invest in circumstances where a solution demonstrates a positive net benefit. This could lead to higher levels of investment, contrary to the objectives underpinning IPART's terms of reference, since under our current planning approach we do not always invest in a solution simply because it demonstrates a positive net benefit. Prudent deferrals, in particular, must be considered. For example, a project may have a positive net benefit at the time of an investigation yet there could be scope to deliver even greater net benefits for customers if the solution is deferred by a year or longer, if possible. This needs to be considered when drafting the principles in clause 5A.3.

Recommendation 7:

The principles in clause 5A.3 of our Licence Conditions should expressly state that the NSW electricity distributors are **not** under a positive regulatory obligation to invest in a solution when a cost benefit analysis demonstrates a positive net benefit.

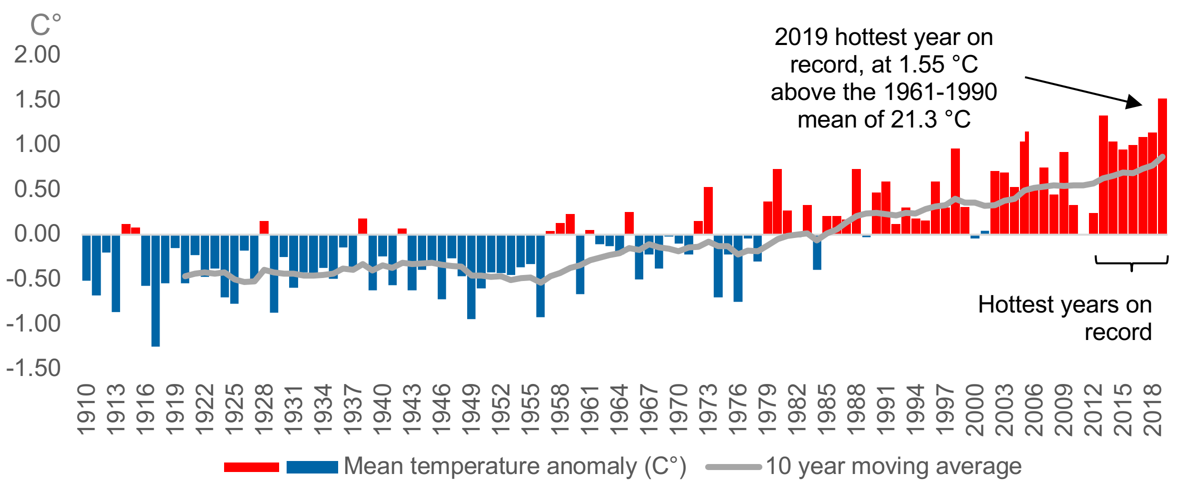
1.3. Rising temperatures and more extreme weather is challenging reliability

As global mean temperatures continue to rise, more extreme weather events are likely to challenge our ability to keep costs down while continuing to maintain reliability at a level our customers value.

Australia recently had its warmest year on record. The 2019 national mean temperature was 1.52 °C above average, well above the previous record of +1.33 °C set in 2013. This is part of a broader trend. Figure 11 sets out the variations in Australian mean temperatures relative to the 1961-90 average. It shows that every year since 2013 has been among the ten warmest on record and, out of those ten warmest years, only one (1998) occurred before 2005.

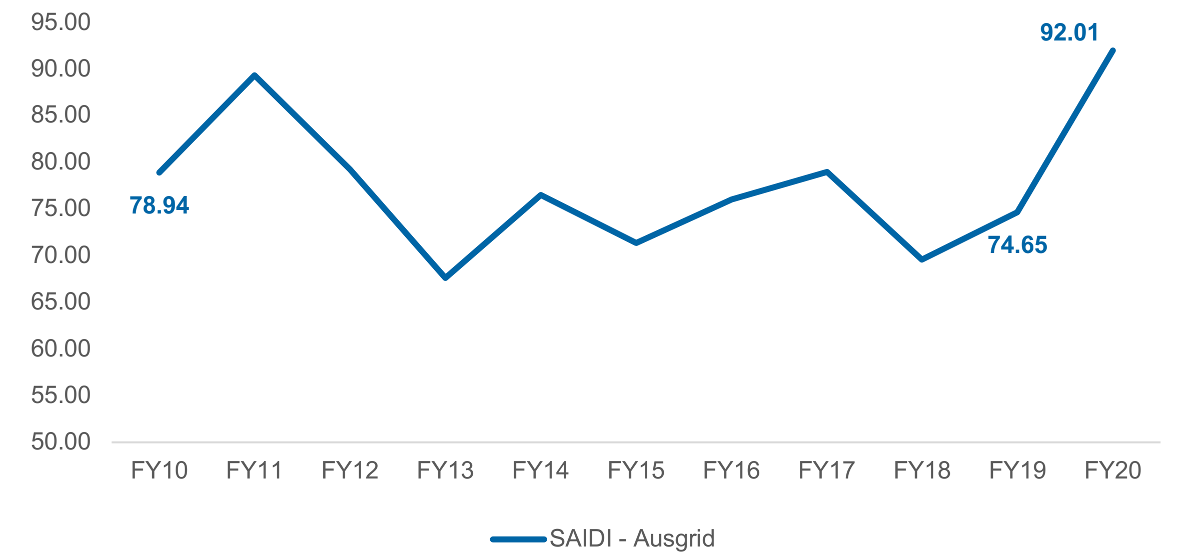
[7] IPART, *Review of Distribution Reliability Standard*, October 2020, p. 51

Figure 11 Australian annual mean temperature variations[8]



Recent extreme weather events are indicative of the challenges we expect to face as global mean temperatures rise. The FY20 storm season left, at its peak, 140,000 of our customers without power as we responded to safety hazards and rebuilt impacted parts of our network. Figure 12 shows the impact on reliability, with the increase in network-wide SAIDI in FY20, relative to our historical performance, revealing the reliability headwinds that lie ahead for our network as weather events become more extreme. In terms of costs, the AER approved the recovery of $26.3 million (real FY20) in additional expenditure related to storm activity in February 2020 alone.[9]

Figure 12 Network wide SAIDI for Ausgrid



IPART has furthermore calculated an 'efficient SAIDI' for our network. Our understanding is that a level of reliability performance in line with these SAIDI values would, in IPART's view, be indicative of

8 Bureau of Meteorology: http://www.bom.gov.au/climate/change/#tabs=Tracker
9 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/ausgrid-cost-pass-through-storm-season-2019-20

an efficient reliability-cost mix. This is given that outperformance would imply investment in reliability is too high while underperformance would indicate it is too low.

We have compared IPART's calculation of our efficient SAIDI with our actual level of reliability. This is shown in Figure 13 for our urban feeders and Figure 14 for our short rural feeders. It shows that in FY20 our urban SAIDI was above IPART's calculation of an efficient SAIDI, while the reliability performance of our short rural feeders was just below the IPART benchmark. Broadly, however, our reliability has been in line with what it appears IPART would consider to be reflective of an efficient reliability-cost mix for our network.

Figure 13 Urban SAIDI performance against IPART benchmark (minutes)[10]

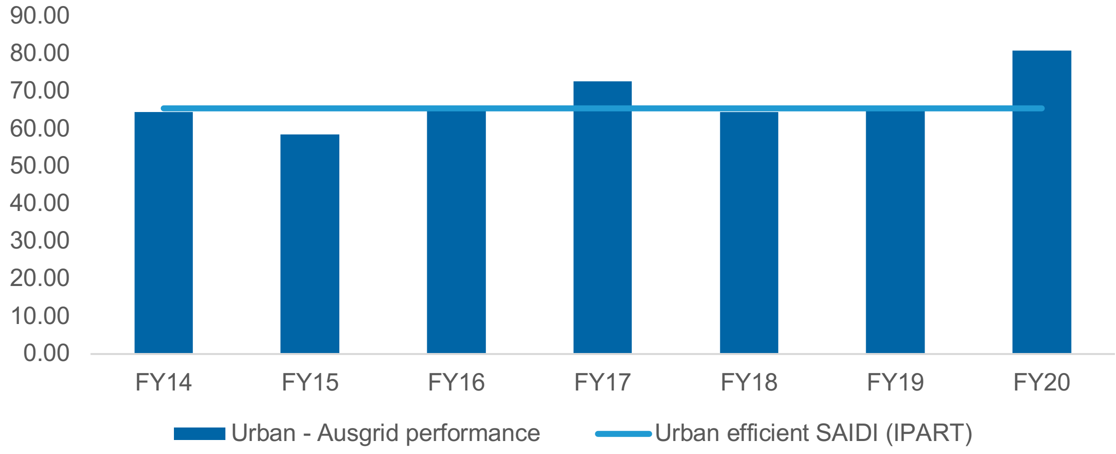
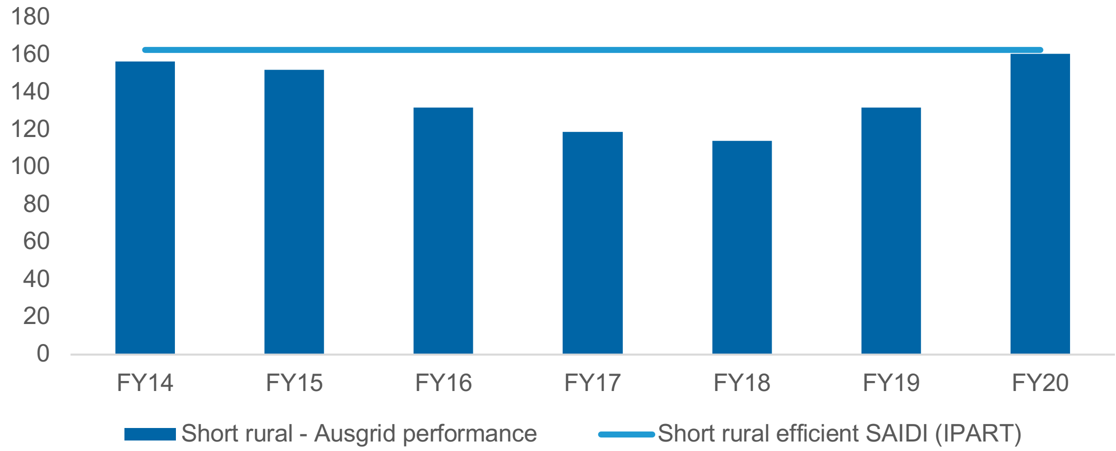


Figure 14 Urban SAIDI performance against IPART benchmark (minutes)[11]



[10] IPART, *Draft Report: Electricity distribution reliability standards*, October 2020, p. 43.
[11] IPART, *Draft Report: Electricity distribution reliability standards*, October 2020, p. 43.

Recommendation 8:

Extreme weather events are already presenting challenges to maintaining a level of reliability that our customers value. IPART's final report should be future focused and consider these reliability headwinds, particularly given that our current level of reliability reflects what was calculated in the draft report to be 'efficient'.

Part 2: Guaranteed service level

The current compensation arrangements for customers who experience long or frequent outages have been in place since 2003. IPART's review presents an appropriate time to consider whether these arrangements are still fit-for-purpose and align to customer expectations.

The cost of the current compensation schemes forms part of our recurrent operating cost base. This provides us with an opportunity, as required under the National Electricity Law, to recover at least our efficient costs.[12] This must be factored into IPART's considerations, particularly if recommending changes that would increase Guaranteed Service Level (GSL) payments.

2.1 Average customer bills will increase under IPART's approach

The Draft Report proposes new GSL arrangements which would lead to material increases in the existing $80 payment. We understand that IPART's intent is that GSL payments act as a "proxy for a refund'.[13] While there may be merit to this approach, particularly if it aligns to customer preferences, it must be recognised that the higher payments would lead to all customers, on average, paying more.

We recommend that IPART consult specifically with customer representatives on this question and consider the proposed approach in light of the review's terms of reference. We note that the current $80 payment updated for general inflation, since its introduction in 2003, would equal $113.55, a $33.55 increase. This alternative payment should be tested with customers.

Table 1 below sets out IPART's proposed tiered payment structure. We have also included the number of customers which would have been entitled to a GSL payment based on our reliability performance in FY20. By using this information, we estimate a total annual cost of $6.4 million based on all eligible customers applying for, and receiving, their entitled payment.

Table 1 Guaranteed service level payments based on FY20 data

	Reliability trigger	Customers	Payment	Cost
Residential				
Level 1	15 hrs or 8 outages p.a.	20,725	$152	$3.2 m
Level 2 (total)	40 hrs or 20 outages p.a.	5,185	$357	$1.9 m

12 National Electricity Law, section 7A (Revenue and Pricing Principles).
13 IPART, *Draft Report: Electricity distribution reliability standards*, October 2020, p. 43.

Business				
Level 1	15 hrs or 8 outages p.a.	1,934	$507	$1.0 m
Level 2 (total)	40 hrs or 20 outages p.a.	408	$976	$0.4m
Total cost				**$6.4 m**

We currently incur about $0.1 m p.a. under the existing $80 payment. The additional costs calculated under IPART's proposed refund model ($6.4 m) would be added to our total cost base that is funded by customers through network charges. If implemented, this would mean that a very small subset of customers (~1%) would pay heavily discounted or no distribution network charges, whilst other customers would on average have higher bills.

The tiered payment structure is also complex and likely to attract more time and effort in explaining to customers and administering claims. These administrative expenses, along with the potential need to update systems, should be factored into the total cost of the proposed GSL arrangements.

The proposed reliability standards state that we are required to publish a dollar value estimate of each annual GSL payment on an 'easily accessible location on [Ausgrid's] website'.[14] We are comfortable with this requirement but have concerns about the additional obligation to inform eligible customers of their right to receive GSL payments 'in **any** information or communication provided by the Licence Holder to customers in relation to a specific interruption (emphasis added)'.[15]

Without clarification, this obligation has the potential to increase compliance costs (for example, through longer telephone calls with our call centre staff). In our view, this obligation should be narrowed to written communication. This would allow the NSW distributors to direct customers to their websites for more information about their right to receive GSL payments.

We would like to engage further with IPART about the timeframes specified in the draft Licence Conditions for making GSL determinations and payments. Clause 6.6(b) requires a payment to be made within 3 months of an application while 6.12 requires the NSW electricity distributors to notify a customer about the outcome of their application within 1 month. From a customer's perspective, these timeframes could be confusing and may require review. In addition, the reporting requirements in clause 7.3 may be difficult and costly to implement. To better manage compliance risks and reduce costs on the NSW electricity distributors, at least 12 weeks (rather than 1 month) should be allowed to prepare and submit the GSL annual report.

14 Proposed distribution reliability standards, October 2020, clause 6.10(a)
15 Proposed distribution reliability standards, October 2020, clause 6.10(b)

Recommendation 9:

We estimate that the total cost of the proposed GSL arrangements could be as high as $6.4 million per annum. Most network bills will be higher if IPART introduces these arrangements, while about 1% of customers would pay heavily discounted or no distributed network charges. These arrangements need to be tested with customers to ensure they align with their preferences. This should include testing whether customers would prefer a more moderate payment such as $113.55 (current $80 payment adjusted for general inflation). We recommend further discussions between IPART and the NSW distributors on this issue.

Recommendation 10:

The proposed tiered GSL payment is complex and likely to attract more time and effort in explaining to customers and administering claims. These additional costs, which may include system changes, should be considered by IPART in deciding whether the changes would deliver net benefits to customers.

Recommendation 11:

The obligation to provide customers with information with the right to receive GSL payments should be narrowed to written communication. IPART should also consider ways to manage compliance risks and reduce costs by reviewing the timeframes for making GSL determinations and payments, as well as the timeframes for regulatory reporting.

2.2 Remitting GSL payments to customers

A further issue we wish to raise in relation to GSL payments is the remitting of payments to eligible customers. We propose that the existing wording in clause 6 of our distribution licence is amended to reflect that in some instances network businesses will be unable to make payments to customers.

The current wording in clause 6 that “A Licence Holder must pay the sum of $80 to a customer” is problematic when customers do not want the payment.

Under the legacy system of cheque payments, it can be evidenced that a payment was made to a customer by reference to the cheque produced and posted to the customer, even if the cheque was never actually banked. However, cheque payments are becoming obsolete and Ausgrid is moving to electronic funds transfer (EFT) payments for GSL payments. We have taken this step for the following reasons:

- Cheque payments require a physical presence in the office: this is the only accounts payable function which requires Ausgrid employees on site, which created a risk during the height of the COVID pandemic as staff members needed to travel to an Ausgrid office to conduct cheque runs.
- Removal of the cost of maintaining cheque infrastructure including stationery, printer and folding machine: it is estimated that each cheque payment costs around $25 per transaction.
- Customers do not want to deal with cheques: many customers do not want to deal with cheques received by mail and contact Ausgrid asking to cancel the cheque and make a payment by EFT instead, as this method is more convenient.

Moving to EFT payments raises the complication that the payment cannot be made if the customer does not want to provide their bank account details. While the number of customers who do not provide their details is quite small, under the current wording of the licence the distributor would not be compliant in these cases, even if it had made reasonable efforts to procure the bank details of the customer. Therefore, when updating distributor licences following this review, we propose that the word “must” be replaced with “must take all reasonable steps to”.

Part 3: Distributed energy resources and SAPS

The regulatory framework the NSW electricity distributors operate under should be responsive to technological change. We therefore support IPART’s review into how our Licence Conditions should incorporate DER and stand-alone power systems (**SAPS**).

3.1 Definitions and scope of the DER reporting requirements

In the proposed Reporting Manual for our reliability standards *DER* is defined as:

> *DER* means distributed energy resources comprising *generating units* and generating systems located on the customer’s side of the metering installation that export electricity into the Licence Holder’s distribution network.[16]

In our view this definition would capture generators of all sizes and types, including registered, non-registered and micro-embedded generators, although it is unclear whether this is IPART’s intention. For example, energy is currently exported into our network from non-registered and registered generators (e.g. solar farms, landfill gas generators, waste mine generators). IPART should clarify whether it is its intention for us to report on all generating units or whether there is a cap on the size or type of the DER system.

If IPART intends to exclude larger generating units, then the current definition of small generating unit used to define the scope of the AEMO DER Register should be adopted. This definition includes any generator not registered with AEMO (typically less than 5MW in size but in some case can be up to 30 MW). An alternative definition to consider would be to use *DER Generation* as defined by the rule change associated with the AEMO DER Register.

> *DER Generation* means distributed energy resources comprising *small generating units* as defined by the National Electricity Rules that export electricity into the Licence Holder’s distribution network.

There are other terms which require greater clarification. It is currently unclear whether ‘static limit’ in the proposed Reporting Manual means total inverter energy rated capacity for an installation, or an export limit set by some device at the connection point. Likewise, it is uncertain if ‘partial static limit’ means an export limit to the grid at the customers connection point set by a device or a dynamic limit that can be changed according to other operational requirements.

Providing greater clarity in what is required, and the meaning of key terms, would promote regulatory certainty and assist in providing consistent reporting across the NSW electricity distributors. We would like to engage further with IPART on these issues. Similar definitional issues are also being considered by the AEMC as part of the DER Integration rule change process.

[16] IPART, Proposed reporting manual: Electricity diction reliability standards, October 2020

Recommendation 12:

IPART should consider adding a 'glossary' of key terms in its Reporting Manual and clarify if all DER units, or just those up to a certain size or type (e.g. inverter energy systems only), are captured by the reporting obligations. Where possible, IPART should use existing industry terms defined in the National Electricity Rules or other relevant rules, standards and guidelines around embedded generation.

3.2 Our ability to comply with DER reporting requirements

There are potential barriers which may prevent us from reporting on all the DER reporting requirements listed in IPART's proposed Reporting Manual. These are outlined below along with other key compliance matters which should be considered in the final report. Our limited visibility of the LV network, particularly at a customer's point of connection, may prevent us from reporting on some of the DER publishing requirements.

Table 2 below summaries the potential compliance risks by setting out each of the DER requirements in clause 3.4 of IPART's proposed Reporting Manual along with an indication of whether we expect to be able to comply, noting that compliance is on a 'best endeavours' basis from FY21-FY24 but mandatory from FY25 with the commencement of our 2024-29 regulatory period.

Table 2 DER reporting requirements in proposed compliance manual

#	Publishing requirement	Comply by FY21	Comply by FY25
i	the number of DER connected to the Licence Holder's distribution network	✓	✓
ii	the volume of electricity exported into the Licence Holder's distribution network from DER	✓	✓
iii	the top ten areas by postcode in the Licence Holder's distribution district that have the highest levels of DER penetration by reference to volume of electricity exported and number of units and/or systems	✓	✓
iv	the volume of electricity that could not be produced due to insufficient hosting capacity of the Licence Holder's distribution network	At risk	At risk
v	the number of complaints from DER customers by reference to postcode relating to constraints impacting the export of electricity from DER	At risk	✓
vi	the number of complaints from customers without DER affected by voltage issues or exceedance of thermal capacity limits due to DER	At risk	✓

vii	the number of customers that are subject to static limits or who are refused connection to the distribution network due to DER	✓	✓
viii	the number of DER customers that are actively being curtailed from exporting any electricity via a total static limit	**At risk**	✓
ix	the number of DER customers that are actively being curtailed from exporting some electricity via a partial static limit	**At risk**	✓
x	the level of operating and capital expenditure by the Licence Holder that is primarily for the purpose of addressing network constraints on DER exports (including justifications for expenditure options).	✓	✓

There is still significant time to pass between now and FY25 when the DER reporting requirements become mandatory. To take advantage of this, IPART should avoid 'locking in' any compliance obligations in favour of taking a more responsive approach to each NSW electricity distributors' actual capabilities. This could be achieved by removing DER measures from the Compliance Manual if it becomes clear, ahead of mandatory reporting in FY25, that reporting against them is not possible or would impose costs that outweigh the benefits to customers. These reporting measures could then be introduced iteratively as we improve our LV network visibility when our internal cost-benefit analysis identifies that it is efficient to do so. We would appreciate the opportunity to discuss arrangements through which the compliance manual could be updated in such circumstances.

Volume of electricity constrained

Clause 3.4(iv) of the proposed Reporting Manual requires the NSW electricity distributors to report on the volume of electricity that could not be produced by a DER system due to insufficient hosting capacity. This is a difficult measure on which to provide accurate information, since it cannot be accurately known how much energy a DER unit would have produced if the network curtailment had not occurred. To meet this reporting requirement, we would have to develop an estimating method which could potentially differ to the approach the other NSW distributors use.

Complaints data due to constraints or voltages issues

Under clause 3.4(vi) of the proposed Reporting Manual, we would be required to report on 'the number of complaints from DER customers by reference to postcode relating to constraints impacting the export of electricity from DER'. In complying with this requirement, it will be highly challenging to decipher whether a DER customer's complaint is network related (hosting capacity) or due to a myriad of other factors, such as incorrect inverter settings or poor design and installation practices by a solar installer (e.g. incorrect voltage rise calculations not meeting the required standards and consumer mains sized incorrectly).

These difficulties can exist at the aggregate 'postcode' level . For example, a solar provider may install multiple solar units in a suburb or street. If all the units have the wrong settings, then the total number of complaints for that area (post code / zone / total) may highlight a network issue for DER that in fact does not exist.

Recommendation 13:

IPART should avoid 'locking in' any DER reporting obligations in favour of taking a more responsive approach to each NSW electricity distributors' actual capabilities. This could be achieved by removing DER measures from the Compliance Manual if it becomes clear, ahead of mandatory reporting in FY25, that reporting against them is not possible or would impose costs that outweigh the benefits to customers. These reporting measures could then be introduced iteratively as we improve our LV network visibility when our internal cost-benefit analysis identifies that it is efficient to do so.

3.3 Stand-Alone Power Systems

IPART is recommending that the NSW Government continue to progress legislative changes to incorporate distributor-led SAPS within the NSW Electricity Supply Act framework as well as incorporate distributor-led SAPS into the National Energy Retail Law (New South Wales), following national implementation of the AEMC's proposed legal and regulatory framework.

At the time of commencement of relevant enabling legislative changes, IPART is recommending that reliability standards should be extended to distributor-led standalone power systems as follows:

- the individual feeder standards to apply to microgrids with feeder-like high voltage distribution lines;
- the individual standards with a default length of 200km to apply to all other distributor-led standalone power systems; and
- apply the guaranteed service levels and payments to distributor-led standalone power systems consistent with how they apply to grid connected customers.

It is important for our Licence Conditions to be responsive to technological changes and we broadly agree with the changes that IPART has proposed for SAPS reliability standards.


Thank you
Ausgrid