10 March 2023

Essential Services Commission of South Australia
GPO Box 2605
ADELAIDE SA 5001

Attention: Rowan McKeown, Senior Policy Officer

Dear Rowan,

SA Power Networks' submission – Electricity Distribution Code Review – Draft Decision

SA Power Networks welcomes the opportunity to make a submission to the Essential Services Commission of South Australia's (the Commission) Electricity Distribution Code (the Code) Review – Draft Decision and provides the following comments on the Commission's Draft Decisions.

In summary, we:

- suggest an amendment to the definition of 'distributor' in the Code to "means a Distribution Network Service Provider regulated by the Australian Energy Regulator whose distribution network is situated in South Australia with 10,000 or more ~~domestic~~ **small** customers";
- accept the Commission's decision to remove Chapter 3 Embedded Generation from the Code. We will work with the Commission and the Office of the Technical Regulator (OTR) to retain any necessary obligations that are currently in Chapter 3 in other jurisdictional instruments;
- agree with the retention of the current reliability service standard targets for the CBD feeder category;
- advocate for a resetting of the reliability service targets for the three other feeder categories, based on the most recent 10-years average historical performance. This will help ensure that regulatory funding is sufficient to maintain the current average reliability performance, in line with the expectations expressed by customers during our engagement activities for the 2025-30 regulatory reset;
- advocate for the EDC to include an outcome-based version of our Network Planning Criteria. These criteria ensure that the risk of large numbers of consumers experiencing long duration outages from High Impact Low Probability Events is efficiently managed;
- agree with the Commission's decision not to set reliability standards for regulated Standalone Power Stations (SAPS) on the basis that these are adequately dealt with under the existing regulatory framework;
- agree with the Commission's decision to remove the streetlight out (SLO) guaranteed service level (GSL) payment, but to retain an amended service standard and reporting obligations on our streetlight performance, and
- would like to work with the Commission on whether a relaxation of the long-standing telephone response service standard (answering 85% of telephone calls in 30 seconds) would now be

appropriate. Doing so would enable us to focus on improving our first call resolution performance and deliver better outcomes to customers with no increase in overall cost. Quantitative customer research undertaken in late 2021 indicated that 'speed in responding to telephone calls' was ranked lowest of 19 customer service attributes surveyed.

Further detailed comments on the Draft Decision are in the attachment to this covering letter.

If you wish to discuss this submission or clarify any points, please contact Mr Grant Cox on 08 8404 5012.

Yours sincerely

Mark Vincent
General Manager Strategy and Transformation

Submission – ESCOSA Electricity Distribution Code review – Draft Decision

March 2023

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SA Power Networks

www.sapowernetworks.com.au

1. Definitions

Definitions of terms used in this report:

Term	Definition
2010-15 RCP	2010-15 Regulatory Control Period or 1 July 2010 to 30 June 2015.
2015-20 RCP	2015-20 Regulatory Control Period or 1 July 2015 to 30 June 2020.
2020-25 RCP	2020-25 Regulatory Control Period or 1 July 2020 to 30 June 2025
2.5β method	The IEEE Std 1366™-2012 2.5 Beta statistical method used to calculate T_{MED}.
AER	Australian Energy Regulator
BoM	Bureau of Meteorology
CBD	Central Business District feeder category
EDC	South Australian Electricity Distribution Code
The Commission	The Essential Services Commission of South Australia
IEEE	US Institute of Electrical and Electronic Engineers Inc
MED	Major Event Day – any day where the daily USAIDI accrued on that day, exceeds a predetermined USAIDI threshold. The threshold is determined in accordance with the IEEE Std 1366™-2012 2.5 Beta statistical method.
USAIDIn	Normalised USAIDI (USAIDI excluding interruptions that start on MEDs)
USAIFIn	Normalised USAIFI (USAIFI excluding interruptions that start on MEDs)
RCP	Regulatory Control Period means the period of a regulatory distribution determination by the AER.
STPIS	The AER's Service Target Performance Incentive Scheme with provides incentive for distributors to maintain or improve reliability performance.
SWE	Significant Weather Event as reported by the BOM in their monthly weather review.
T_{MED}	The daily USAIDI threshold used to determine if a day will be classified as a MED.
UCAIDI	Unplanned Customer Average Interruption Duration Index (ie average time taken to restore supply to customers as a result of an unplanned interruption)
USAIDI	Unplanned System Average Interruption Duration Index – total number of minutes, on average, that customers are without electricity as a result of unplanned interruptions[1] in a year.
USAIFI	Unplanned System Average Interruption Frequency Index – average number of times customers' supply is interrupted per year from unplanned interruptions.

1 Excludes interruptions where the duration is less than three minutes.

2. Application of the Code

2.1 Electricity Distributors

The Commission's draft decision is for the Electricity Distribution Code (EDC) to apply to any Distribution Network Service Provider (DNSP) regulated by the Australian Energy Regulator (AER) in South Australia with 10,000 or more domestic customers.

SA Power Networks is concerned that the Commission has introduced a new term 'domestic customers' into the definition of a distributor within the EDC. The National Energy Customer Framework introduced in South Australia in February 2013 uses various descriptive terms for customers like, residential, business, small and large customers and does not use the term domestic. The NECF provides protections to all small customers which are defined, in the National Energy Retail Law, as a customer:

- who is a residential customer; or
- who is a business customer who consumes energy at a business premises below the upper consumption threshold (this threshold is 160MWh pa in South Australia).

Consequently, SA Power Networks recommends that the EDC should define a distributor as:

"means a Distribution Network Service Provider regulated by the Australian Energy Regulator whose distribution network is situated in South Australia with 10,000 or more ~~domestic~~ **small** customers"

2.2 Embedded Generators

The Commission's Draft Decision is to remove Chapter 3 Embedded Generation from the EDC. This decision is because most of the technical requirements in Chapter 3 are either duplicated in National or Jurisdictional obligations or in SA Power Networks technical standards. SA Power Networks' technical standards are only enforceable because they are specified in Technical Installation Rules (TIRs) by the Office of the Technical Regulator and invoked by the Electricity (General) Regulations s55.

SA Power Networks proposes to work with the Office of the Technical Regulator and ESCoSA to review the matters identified by Engevity and include relevant obligations in other jurisdictional instruments as appropriate.

Currently the Commission is exempting embedded generators with a capacity of up to 1,000 kW from being licensed under the Electricity Act.

SA Power Networks has developed several standard connection agreements for connecting embedded generators to the distribution system. Requirements in these connection agreements are commensurate with the potential harm to the network and other customers they may cause. These contracts vary for generators greater than 30kW. To minimise the harm that can result from the connection of embedded generators to our distribution network we recommend that any generator who is exempt from being licensed should be required to establish and maintain a connection agreement with SA Power Networks.

3. MINIMUM SERVICE STANDARDS

3.1 Commission's Draft Decision

The Commission's Draft Decision is to retain the current EDC minimum reliability service standard targets for Urban, Rural Short and Rural Long feeder categories for the 2025-30 RCP:

"The draft decision is that targets in the current Code will be retained. These targets will facilitate reliability outcomes that satisfy consumer expectations, are consistent with those delivered by other NEM distributors, and exceed the reliability outcomes delivered before the privatisation of distribution services in South Australia."

We are concerned the Commission is proposing to not reset the reliability targets on recent historic performance, which has been the Commission's prior practice. By not resetting the targets, it would permit us to decline the reliability levels which is contrary to preferences expressed by customers in our customer engagement as part of our 2025-30 Reset process.

Table 1 below highlights the difference between the current reliability targets and the 10-year historic performance, for Urban, Rural Short and Rural Long feeder categories. The Table demonstrates the improvement in the average reliability received by customers when compared to the EDC targets.

Table 1 - Current EDC reliability targets and recent 10-year average historic performance

	Urban		Rural Short		Rural Long	
	EDC	10-year ave.	EDC	10-year ave.	EDC	10-year ave.
USAIDIn	110	101	200	175	290	280
USAIFIn	1.15	1.03	1.65	1.35	1.75	1.53
Restoration 1	27%	25%	27%	24%	30%	30%
Restoration 2	11%	11%	8%	8%	10%	10%

The improvements in reliability have benefited customers who have partially funded those improvements through benefits provided to us by the AER's Service Target Performance Incentive Scheme (STPIS), and customers should receive the benefit of those improvements in the future. We recommend that the Commission resets the reliability targets consistent with past practice.

3.2 Findings from the Reset customer engagement

In developing with our 2025-30 Regulatory Proposal, in 2022 we held a series of specific 'Focussed Conversations' with customers to seek their views on what work programmes we should be incorporating into the 2025-30 RCP. The feedback on reliability programmes was clear: customers wanted us to maintain current levels of reliability and to restore the reliability service levels in the Adelaide Central Business District (CBD). In addition, they supported specific improvements in regional reliability and 'worst-served' customer reliability improvement.

A 'People's Panel' was then convened in 2023 to consider all the Focussed Conversations recommendations to determine an overall price-service 'package' of all works to be undertaken in 2025-30. The People's Panel endorsed in full the reliability initiatives recommended from the Focused Conversations.

Customers were also appraised of our network planning criteria, used to determine when the distribution system requires capacity reinforcement due to increases in customer load. There was strong support for continuing with our network planning criteria (planning standards) to determine when the distribution network requires reinforcement.

3.3 Reliability targets conclusion

We consider that the Commission's Draft Decision, to retain the current reliability standards targets, does not align with our customers' preferences: that current reliability service levels should be retained. Consequently, we recommend that the reliability targets are reset to those outlined in Table 2 below.

Table 2 - Proposed EDC reliability targets for 2025-30 RCP

2025-30	CBD	Urban	Rural Short	Rural Long
USAIDIn	15	100	175	280
USAIFIn	0.15	1.05	1.35	1.55
Restoration 1	11%	25%	24%	30%
Restoration 2	4%	11%	8%	10%

3.4 Standalone Power Systems

The Commission Draft Decision is that minimum reliability standards will not be set for Standalone Power Systems, because these are provided for by the national regulatory framework. SA Power Networks agrees with the Commission's decision and the reasons.

3.5 Safety net planning requirements

Our Network Planning Criteria sets out when augmentation of the distribution network is required, to mitigate the risk of overloading assets with increasing demand and providing a level of resilience to cope with High Impact Low Probability (HILP) events. Our well-established planning criteria, strikes an appropriate balance between minimising cost to consumers whilst maintaining a secure electricity system that protects customers from widespread and excessively long outages as a result of HILP events.

We consider that these criteria should be codified as an obligation on SA Power Networks, as the current regulatory framework and probabilistic methods for justifying network augmentation expenditure does not adequately cater for HILP events. That is, even though the consequences of a major item of plant can result in wide-spread and long-duration outages for many customers, the probability of these events are very low and expenditure justification using the Value of Customer Reliability is difficult. We argue that simply using the Value of Customer Reliability, as per the regulatory economic framework, undervalues investment required to manage the very extreme events.

The Commission's Draft Decision is not to include our Network Planning Criteria in the EDC. The Commission advised that:

> "The Commission does not support SA Power Networks' proposal. It is important that any approach to planning for HILP (High Impact Low Probability) events is not prescriptive. Decisions about whether resilience-related expenditure is valued by consumers necessarily require judgement, best informed by analysis of several types of evidence. This is provided for by the existing best endeavours regulatory obligation.
>
> The AER has published guidance for network service providers on the evidence needed to support proposals for network resilience-related expenditure. Its approach involves establishing the value to consumers of expenditure for network resilience to possible HILP events, while acknowledging the limitations of using conventional techniques to do so, and so a role for other supporting evidence. The Commission supports the AER's approach."

SA Power Networks has reviewed the AER's Guidance note on resilience and notes that it is focused on preparation for responding to natural disasters. SA Power Networks already has in place several of the examples detailed in the Guidance note to assist in responding to natural disasters. The primary objective of our Network Planning Criteria is to minimise the numbers of customers affected by long duration outages or rotational load shedding, as a consequence of plant failure. It is important to note that major plant failure is often unrelated to weather and/or natural disasters.

Our Network Planning Criteria has been refined over decades prior to privatisation in 2000 and used consistently since then. In determining when the network should be augmented, it strikes the right balance between risk and cost to consumers. It also forms part of our operational planning for major plant failures. Our criteria is similar to the service standards contained in the Electricity Transmission Code (ETC section 2). The ETC details the planning and reliability standards that apply to ElectraNet. Similarly, our planning criteria vary depending on the level of redundancy (eg N or N-1) in the supply arrangements and the numbers of customers that will be affected if a major piece of plant fails.

There is a prudent level of risk that is incorporated into our planning criteria to avoid over-investment. This level of risk can be managed operationally with the use of mobile plant, including mobile generators and mobile substations. Investment in network augmentation is a last resort for manage increased demand, with alternative options exhausted, including load balancing across the network.

AER staff have confirmed they will only approve augmentation expenditure where the NPV of the costs of augmentation are less than the cost to customers multiplied by the risk of the plant failure (ie Probabilistic Planning Criteria). As noted above, it is difficult to justify expenditure to mitigate against HILP events on this basis given the low likelihood, despite the very extreme consequences. Importantly, though low in likelihood, these events are credible and can and do occur in practice, as evidenced in Western Australia recently. These same events have also occurred in South Australia, however the resilience built into our distribution network, as a result of our planning criteria, has minimised the impact on the community.

There was an Independent Review into Western Power's response to the Christmas 2021 outages on the South Western Networks in Western Australia. The occurrence of High Impact Low Probability event, in this case prolonged and extreme heat, resulted in widespread customer interruptions. The Review made several recommendations but one related to a review of its planning criteria (Recommendation 2) which was[2]:

[2] Independent Review of Christmas 2021 Power Outages Final Report page xii

"Western Power should review its approach to network planning, particularly the ongoing appropriateness of its application of distribution network planning criteria, to identify improvements.

This review should recognise the appropriate economic trade-off between customer reliability and cost to supply given greater uncertainties in future demand and supply of electricity. These uncertainties relate to changes in climate (and more frequent and severe extreme events), customer electricity usage and the growing impact of technologies such as solar PV, batteries and electric vehicles.

Western Power should then engage with the Economic Regulation Authority (ERA), through existing approval processes, regarding the implementation of any changes to the Technical Rules."

This review highlights the potential consequence of applying a purely probabilistic approach to network planning.

We understand that the Commission's view is that approval of projects resulting from increased customer demand is the AER's responsibility. However, rejection of projects which meet our Network Planning Criteria but are considered uneconomic by the AER on the basis of VCR alone, will have adverse customer outcomes under HILP events.

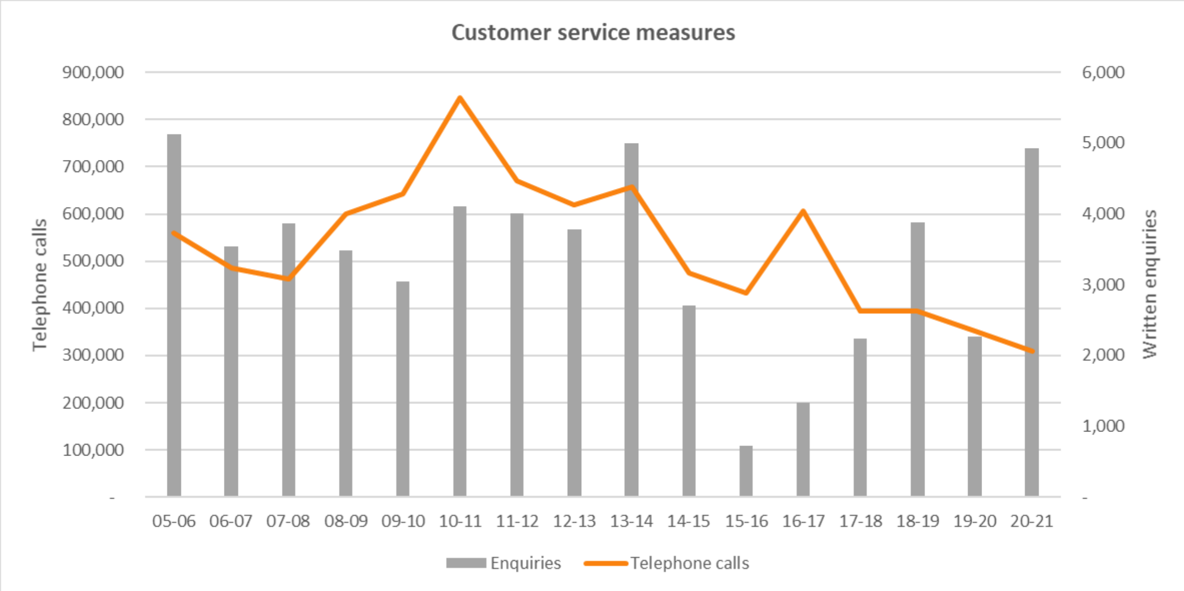
We consider that the Commission should specify standards which deliver appropriate supply reliability outcomes for customers when a major piece of distribution network plant fails. We would be willing to work with the Commission to establish appropriate service standard outcomes that deal with major plant failures to minimise the long duration outages to large numbers of customers from such events.

3.6 Minimum customer service standards

SA Power Networks has previously noted some existing customer measures are now less relevant for customers. The main measure of concern is answering a telephone call within 30 seconds. **Error! Reference source not found.** below illustrates the gradual halving of the number of telephone calls SA Power Networks has received from customers since 2005-06.

Figure 1 also shows that, while there is significant variation annually, the number of written enquiries from customers on average has remain steady. This would indicate that responding to written enquires (which now include social media enquiries) is still relevant for customers.

Figure 1 - Current customer service measures

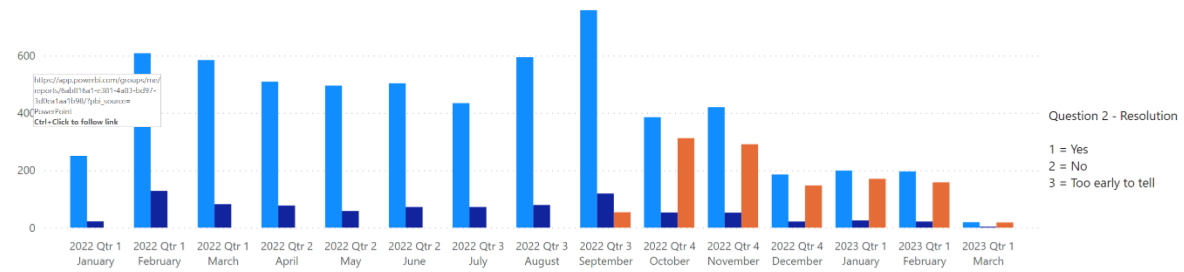


Since 1 July 2020 we have been reporting additional customer service measures which focus on how satisfied customers are with our performance in the following areas:

- Planned interruptions
- Unplanned interruptions
- New connections, and
- Customer complaints.

These measures are based on surveys of customers who have been in contact or received contact from SA Power Networks in the above areas. There are several distributors which are also using these measures, so we can compare our performance with other distributors. SA Power Networks compares favourably to the industry benchmark in these four areas.

Figure 2 - Customer responses to first call resolution



SA Power Networks considers that answering phone calls in 30 seconds is less valued by customers compared with getting their query/enquiry/compliant resolved at the initial telephone call. We consider that customers would be willing to wait longer on a call to get their query resolved at that first contact. Consequently, we have commenced (in January 2022) measuring 'first call resolution'. We survey customers after they have called to determine if, in their opinion, their query was resolved at the first call. Figure 2 below highlights our first call resolution performance since January 2022. It highlights calls resolved, calls not resolved and calls where it is too early to tell (eg follow up work required to resolve the customer's issue).

Consequently, we have been focusing on improving our first call resolution performance. However, this focus has seen a decline in the telephony measure performance of our General Enquiries (GE) and Builders & Contractors (B&C) telephone line, where the performance has declined from more than 90% of calls answered in 30 seconds (January 2022) to less than 70% of calls answered in 30 seconds in December 2022.

We consider that the current service standard is preventing us from focusing on improving our first call resolution and would like to work with the Commission to establish relaxed standards for telephone answering once more data is available. For example, the Commission could consider revised like:

- Fault and Emergency calls continue to have a service standard of 85% of calls answered within 30 seconds (this would in streetlight out reporting as well); and
- General Enquiries and Builder & Contractors service standard would be set at a rate of 75% of telephone calls answered within 60 seconds.

4. STREETLIGHT REPAIR OBLIGATIONS

4.1 Public Lighting services

SA Power Networks provides public lighting services for 69 public lighting customers throughout South Australia, including local councils and the South Australian Department of Infrastructure and Transport (DIT). These services involve the installation, maintenance, inspection, and operation of approximately 240,000 public lights installed on SA Power Networks distribution network.

The EDC currently has two provisions that apply to SA Power Networks' public lighting operations, including:

- a street light repair service standard; and
- a street light repair Guaranteed Service Level (GSL) payment.

4.2 Street light repair service standard

The EDC requires that SA Power Networks must use its best endeavours to repair street light faults affecting lights for which it is responsible within five business days in metropolitan Adelaide, and within ten business days elsewhere[3].

In collaboration with the Local Government Association of South Australia (LGA) and the Public Lighting Working Group (PLWG), SA Power Networks implemented a Public Lighting Service Framework from 1 July 2020. This service framework details the target levels of services to be delivered to public lighting customers, including repairing 98% of public lighting faults within 5 business days (metro) or 10 business days (regional).

Recognising the introduction of this Public Lighting Service Framework, the Commission's draft decision is to remove the street light repair service standard from the EDC.

[3] Clause 2.3.1(b)(i)

Following consultation with public lighting customers, SA Power Networks' preference is to retain the street light service standard within the EDC, providing continued regulatory oversight by the Commission.

Public lighting customers have expressed concern regarding the level of transparency around existing fault reporting. SA Power Networks acknowledges this concern and is working to implement new operational performance reporting as part of our public lighting customer portal, providing public lighting customers with fault reporting for their specific service area. These performance reports are expected to be available later in the current regulatory period.

SA Power Networks recommends retaining an updated street light repair service standard within the EDC, including different timeframes for simple and complex faults. This is discussed further below. The inclusion of public lighting service standards within the EDC should be reviewed again prior to the 2030-35 regulatory period.

4.3 Street light repair GSL payment

The EDC requires SA Power Networks to make a GSL payment to the first person to report a street light fault if it is not repaired within five business days (metro) or ten business days (regional). A payment of $25 applies for each subsequent five or 10 day period in which the fault is not repaired.[4]

The Commission's draft decision is to remove the street light repair GSL payment from the EDC, on the basis that its benefit is limited to being a weak incentive for people to report street light outages. A low and manageable risk remains that there will be fewer reports of street light outages without the GSL payment.

As a transitional measure, the Commission proposes to retain the annual reporting on street light outages and repairs during the 2025–30 period to monitor the impact of removal of the GSL payment.

SA Power Networks is supportive of removal of the GSL payment from the EDC. We note there are mixed views from public lighting customers: some are supportive of removal of the GSL scheme, while others are concerned that individuals would cease pro-actively reporting lights out if there was no GSL scheme in place. The general preference expressed in the PLWG meeting on 15 February 2023, was to retain a GSL payment for public lighting within the EDC.

Where a GSL payment is retained, SA Power Networks is supportive of the scheme being amended to:

- Provide a single GSL payment of $25 to the first person who reports the fault, and the fault is not repaired within the required times; and
- Introduce different fault rectification times for simple and complex faults.

These are discussed in more detail below.

4.3.a Single GSL payment

Multiple GSL payments for a single fault, provides an incentive for individuals to report a fault on the basis that they may receive a payment (noting that only 7% of fault reports receive GSL payment).

The South Australian streetlight GSL payment regime incentivises 'serial' reporting. The behaviour witnessed from serial reporters, to maximise their SL payments, is to:

[4] Clause 2.3.1(b)(ii)

- report 40 or more faults in a single night; and
- report working streetlights as a fault[5].

This behaviour overwhelms our ability to respond and repair actual faults within the guaranteed time.

If the GSL regime in South Australia was altered to a single GSL payment of $25 being made when a streetlight is not repaired within the required time, then this would reduce the cost of the GSL scheme from approximately $200,000 per year to approximately $50,000 per year, reducing the overall cost for public lighting customers.

The move to a single GSL payment is strongly supported by public lighting customers: 85% of public lighting customers surveyed as part of our Focussed Conversation Engagement Program (7 October 2022) indicated their support for this approach.

4.3.b Simple and complex fault rectification timeframes

There are two classes of faults that result in a streetlight being out, which are:

- Simple/general faults (eg Globe within the streetlight has failed); and
- Complex faults (eg cable fault in the underground cable supplying the streetlight).

It is practical to attend a faulty streetlight and repair it for a simple fault within five business days, but it not practical to repair a complex fault within five business days. For a complex fault, multiple visits may be required to locate the root cause, before repairs can be made. Some cases may require giving reasonable notice (typically two weeks) before entering private property to effect repairs.

The NSW streetlight regime recognises that different classes of faults can result in different repair times, classifying streetlight faults into general and complex faults. The NSW regime provides the distributor with 10 business days to repair a general fault and 30 business days to repair a complex fault. If the distributor exceeds these repair times the first person[6] to report the SLO receives a single $25 GSL payment.

SA Power Networks considers that repair times for streetlight repairs and the associated GSL payment need to reflect the different classes of faults. This would also highlight to SLO reporters that some types of faults require a greater time to repair. The current SLO GSL regime of applying a single repair to all SLO faults, is costing SA Power Networks (and Public Lighting customers) about an additional $1m over a regulatory control period when compared to the GSL regimes operating in other mainland NEM states.

Public lighting customers generally support the introduction of different performance targets for complex and simple faults, with 86% of public lighting customers surveyed as part of our Focussed Conversation Engagement Program (7 October 2022) indicating their support for this approach.

SA Power Networks recommends adopting the NSW definition of complex faults, where a complex fault is defined as where:

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[5] In calendar year 2018 and 2019 a serial reporters reported 1,000 SLO of which 28% were found to be working when attended. The serial reporter was paid $9,000 in GSL payments but it cost nearly $25,000 to attend working streetlights. These crews could have attended and repaired streetlight which were not working. In calendar years 2018 and 2019 14% of SLO reports were for working streetlights, which cost in in excess of $0.6m to attend.

[6] The first person who abuts the streetlight or a public lighting customer (eg Council to whom the distributor is providing streetlighting services).

- a site-specific traffic management plan and an additional dedicated traffic control crew are required; or
- a site-specific Road Occupancy Licence or other specific authority for road occupancy is required; or
- identification of an underground fault is required.

Simple faults would be repaired within 5 business days (for both metro and regional faults) with complex faults to be repaired within 30 business days.

4.4 Conclusion

The current South Australia public lighting GSL regime detailed in the EDC creates significant additional costs, ultimately born by public lighting customers and their ratepayers. The GSL regime provides no additional benefit to ensuring that streetlights are working, when compared to simpler and more effective GSL regimes that operate in other mainland NEM states (ie NSW and Victoria).

The street light service standard should be retained within the EDC but amended to differentiate between simple and complex faults.

We generally support the Commission's draft decision to remove the GSL payment for public lighting, with annual reporting on street light outages and repairs during the 2025–30 period retained to monitor the impact on fault reporting.

However, we note that Commission staff have signalled the possibility of reintroducing a GSL payment mid-period if there is an unexpected drop in street light outage reports. We have commenced discussions with the AER on how we may be able to get cost recovery if the GSL is reintroduced mid period, that is to include provision for the GSL within AER approved price public lighting caps. We believe there is scope to include the GSL within the 'A' factor within the Alternative Control Services price cap form of control. This requires further discussion with the AER to ensure SA Power Networks is able to recover the reasonable costs of the GSL scheme from public lighting customers.