Supporting document 5.4

ESCoSA Reliability Standards Review

2020-2025 Regulatory Proposal

1 January 2019

Electricity

SA Power Networks reliability standards review

Final decision

January 2019

Enquiries concerning this Final Decision should be addressed to:

Essential Services Commission
GPO Box 2605
ADELAIDE SA 5001

Telephone:	(08) 8463 4444
Freecall:	1800 633 592 (SA and mobiles only)
E-mail:	escosa@escosa.sa.gov.au
Web:	www.escosa.sa.gov.au

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Glossary of terms

Term	Explanation
ABA	Adelaide Business Area
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMA	Adelaide Metropolitan Area
CAIDI	Customer Average Interruption Duration Index
CBD	Central Business District
Code	Electricity Distribution Code version 12.1
Commission	Essential Services Commission, established under the Essential Services Commission Act 2002
Duration payment	Duration of interruption GSL payment
Electricity Act	Electricity Act 1996
ESC Act	Essential Services Commission Act 2002
Frequency payment	Frequency of interruption GSL payment
GSL	Guaranteed Service Level
IEEE	Institute of Electrical and Electronics Engineers
IEEE method	The method for normalising reliability performance set out in the Institute of Electrical and Electronics Engineers (IEEE) standard 1366-2012
IVR	Interactive Voice Response
MAIFI	Momentary Average Interruption Frequency Index
MAIFIe	Momentary Average Interruption Frequency Index event
MECS	Monitoring, Evaluation and Compliance Strategy
MED	Major Event Day
MRC	Major Regional Centres
MWh	Megawatt hours
Review	SA Power Networks reliability standards review 2020

Term	Explanation
SACOSS	South Australian Council of Social Services
Street light payment	Repair of faulty street light GSL payment
SMS	Short Message Service
STPIS	Service Target Performance Incentive Scheme
Total duration payment	Total annual duration of interruption GSL payment
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Frequency Duration Index
VCR	Value of Customer Reliability

Overview

This is the Essential Services Commission's (**Commission**) final decision on the review of the reliability framework that will apply to SA Power Networks and take effect from 1 July 2020 to 30 June 2025 (**Review**).

Final decision

The Commission's final decision sets out that, for the 2020 – 2025 period, network reliability standards will be set to require SA Power Networks to maintain reliability at current levels, rather than improve or reduce performance. Performance targets will continue to apply to feeder-type categories.

This approach is supported by results of a customer survey showing customers are satisfied with reliability outcomes, and have limited willingness to pay for reliability improvements. Results of economic assessments show no clear economic benefit in setting targets to improve performance.

SA Power Networks' total expenditure to maintain jurisdictional reliability standards will be $37 million over the 2015 – 2020 period. It has indicated that expenditure associated with maintaining reliability at current levels would be similar over the 2020 – 2025 period. Without this investment, average reliability would decline by less than one per cent, and a typical annual residential electricity bill would be reduced by approximately $2 per annum over the period.

The final decision will replace current one-off duration of interruption Guaranteed Service Level (**GSL**) payments (**duration payments**) with total annual duration of interruption payments (**total duration payments**).

This will manage the cost of the GSL scheme and refocus it on customers with ongoing, persistent reliability issues. This approach is supported by evidence: that customers are not willing to pay as much as they do now for the GSL scheme; that many payments are currently being made to customers that generally have average or good reliability; and, that current levels of duration payments are not a strong driver of SA Power Networks' response to interruptions.

Further changes to the GSL scheme set out in this decision include: replacing tiered frequency of interruption GSL payments (**frequency payments**) with a flat payment, and removing GSL payments for late attendance at appointments.

From 1 July 2020, SA Power Networks will be required to report annually on its performance in ten regions, which were proposed as the basis for network reliability standards in the draft decision. It will be required to report directly to its customers on its reliability performance, to fulfil regular reporting requirements, to provide explanations when it misses performance targets, and following significant network outages. This will increase SA Power Networks' direct accountability to its customers.

SA Power Networks is the owner and operator of South Australia's main electricity distribution network that connects over 890,000 customers to the national electricity grid. The reliability of its distribution services are regulated jointly by the Commission and the Australian Energy Regulator (**AER**). The broader economic regulatory framework supports and challenges SA Power Networks to:

- provide services at the lowest sustainable price for the quality and reliability valued by customers, and
- have in place sound and long-term asset management, operating and financing strategies and delivery, which support the provision of those services for customers of today and tomorrow.

The Commission reviews the reliability service standards that apply to SA Power Networks every five years, prior to the commencement of a new revenue regulation period. The Commission's reviews seek to establish reliability standards that are valued by customers. The AER then assesses whether SA Power Networks' plans for delivering these standards are prudent and efficient, in order to determine its revenue requirement.

In establishing reliability levels that customers value, the Commission's primary objective is to protect the long-term interests of South Australian consumers with respect to the price, quality and reliability of the distribution services SA Power Networks provides. This requires an assessment of the trade-off between price and reliability.

Higher distribution network reliability may provide extra benefits to customers, but may also raise costs and prices. In competitive markets, the price-service mix is optimised by consumers choosing the service they prefer, given the price. As monopolies, electricity distributors such as SA Power Networks are not subject to competitive forces influencing the price and quality of the distribution services they provide. Coupled with revenue regulation, service standard regulation seeks to determine efficient service levels for distribution services, given the absence of a competitive market.

Resolving the trade-off between price and reliability means identifying an acceptable level of network availability. This requires assessing the costs of delivering alternative reliability outcomes against customers' willingness to pay for that service.

When considering an 'acceptable level' of availability, it is important to note that the South Australian energy market has changed markedly since the Commission last reviewed SA Power Networks' reliability standards in 2013-14. There have been changes in technology and in customer demand for energy services. In addition, extreme weather has focused attention on network resilience and response to outages. These changes have sharpened community focus on both reliability and price.

It is also important to recognise that the reliability experienced by customers is not driven solely by the reliability of the distribution network: it is also determined by the reliability of the transmission network and the reliability of generation.

The Commission's current reliability framework for SA Power Networks is established in the Electricity Distribution Code (**Code**) and has four main elements: network reliability standards, customer service standards, the Guaranteed Service Level (**GSL**) scheme and monitoring and reporting requirements.

The changes in this final decision will result in two main enhancements to the Commission's current framework:

- increasing SA Power Networks' accountability to its customers for its reliability performance through an enhanced regional reporting regime, and
- controlling the costs of the GSL scheme by refocusing payments to customers with ongoing, persistent reliability issues.

Each decision point is summarised in Table 1, together with departures from the draft decision.

Maintaining reliability at current levels

The Commission's decision is to set network reliability standards to maintain reliability at current levels, rather than setting targets to improve or reduce performance.

This final decision is supported by results of a customer survey showing that 73 percent of customers are satisfied with overall reliability outcomes, and have limited willingness to pay for reliability improvements.[1] It is further supported by the results of the Commission's economic assessments, which show no clear economic benefit in setting targets to improve performance.

The level of customer satisfaction has declined since the last survey was conducted in 2013. At that time, 88 percent of customers were satisfied with reliability outcomes. While any decline in customer satisfaction needs to be carefully considered, the results are likely to be partly explained by customers' feelings about the large-scale outages that occurred in the 18 months prior to the customer survey.

[1] Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages*, Final Report, August 2018, available at https://www.escosa.sa.gov.au/ArticleDocuments/1186/20180801-Electricity-EconomicAnalysisReliabilityImprovementPackages-SSF20Report-OakleyGreenwood.pdf.aspx?Embed=Y.

In making their comments on SA Power Networks' performance, customers are likely to have been unaware that these outages were the result of transmission and generation failures, rather than the actions or inactions of SA Power Networks. The Commission has taken these wider contextual matters into account in considering the decline in satisfaction.

Standards for feeder categories, with an enhanced regional reporting regime

For 2020 – 2025, distribution network reliability standards will continue to apply to four feeder-type categories. This reverses the draft decision that standards would apply to ten region-based categories. The Commission has made this decision because:

- It considers that the improved communication, accountability and transparency stakeholders want can be achieved through an enhanced reporting and monitoring regime.
- It has heard that customers are broadly satisfied with current reliability outcomes, and they are not prepared to pay for reliability improvements. Customers are sensitive to any potential cost increases. The Commission expects SA Power Networks to distribute its existing resources efficiently to maintain regional reliability performance. While there is the potential for reliability performance to decline in regions over time, there is no evidence to suggest that such declines have occurred. However, the Commission will not hesitate to step in to require targeted improvements in specific areas where there is strong evidence that is required.
- It takes into account recent revisions to the AER's Service Target Performance Incentive Scheme (**STPIS**), which will provide a greater incentive to reduce the duration of interruptions. This is likely to benefit customers in regions, who are more likely to experience longer duration interruptions.
- Though it considers that accommodating off-grid supply is important, the Australian Energy Market Commission (**AEMC**) has yet to make the rule changes required to allow off-grid supply as an alternative to grid-supplied network services. The Commission will await the AEMC's decisions before adjusting jurisdictional standards, if required.

The Commission will implement an enhanced reporting regime, which requires reporting on ten region-based categories, rather than the current seven regions. SA Power Networks will be required to produce a series of annual regional reports that include high level explanations of year-to-year variation, to assist customers to understand performance in their area. These regional reports will be made available on SA Power Networks' website.

The Commission will conduct periodic assessments of the systems, processes and controls used by SA Power Networks to prepare and provide those reports, including the underlying data quality. It will also continue to issue long-term industry performance trends and statistics, and provide analysis of key events or compliance matters as necessary. Reports published by SA Power Networks will also be made available through the Commission's website.

Providing GSL payments for customers with ongoing, persistent reliability issues

The Commission considers that a jurisdictional GSL scheme remains beneficial for customers experiencing reliability issues, and is preferred to the GSL scheme included in the STPIS. A jurisdictional scheme can allow for local conditions, and reflect South Australian customers' willingness to pay. To manage scheme costs, and better target customers with ongoing, persistent reliability issues, the Commission will amend its GSL scheme.

Current duration of interruption payments (**duration payments**) will be replaced with new total annual duration of interruption payments (**total duration payments**). There will be three total duration payment bands, with payments starting at $100 for between 20 and 30 hours of interruptions in a financial year, to $300 for more than 60 hours of interruptions.

In addition to this, the Commission will replace the current frequency of interruption payments (**frequency payments**) with a flat payment for customers who have more than nine interruptions (excluding momentary interruptions) in a financial year. This will further reduce the costs of the GSL scheme.

As duration payments for one-off outages are removed, restoration time targets will be reintroduced. These will increase transparency around restoration times, and inform customers as to what they can generally expect of SA Power Networks when an outage occurs.

GSL payments for late attendance at appointments will be removed from the scheme. SA Power Networks now has few direct appointments with customers, which was not the case when the GSL scheme was initially designed.

GSL payments for promptness of new connections, and timeliness of street light repairs will remain. Though the Commission's draft decision was to remove street light repair GSL payments, more information is needed on how public lighting service levels will be defined from 2020 before the purpose of the street light payment can be clarified, and redesigned if necessary.

Standards for new communication channels

Customers rely on many channels to communicate with and gain information from SA Power Networks. The Commission will add to its existing telephone and written responsiveness requirements to reflect the diversity of the methods of communication currently being used.

The Commission will introduce an overall communications quality measure to capture all commonly used communications channels, including the traditional channels of telephone and written enquiries, and newer channels including the corporate website, SMS messages, social media (currently Facebook and Twitter) and other media (print, radio and online).

Next steps

The final network reliability performance targets will be established once data for 2018-19 are available, with final targets set in late 2019. The matter of whether performance targets will be set as the average of five or ten years' performance will be settled at that time.

Public consultation will occur on the consequential amendments to relevant regulatory instruments, namely the Code, and Electricity Guideline No. 1 G1/12 – Electricity Regulatory Information Requirements – Distribution (Electricity Guideline No. 1).

Table 1: At a glance - summary of decision points (departures from draft decision are shown in bold)

Section/element	Current arrangement	Arrangement for 2020 - 2025
3.1 Overall level of service: maintain, reduce or improve?	Performance targets based on five years' historical performance prior to start of regulatory period.	Maintain reliability at current levels, for metropolitan and regional customers, and for low reliability feeders. Performance data for both the five and 10-year periods analysed to assess preferred basis.
3.2 Measures of network reliability	Average duration and frequency of interruptions (USAIDI and USAIFI).	Continue: no change.
3.3 Measures will apply to feeder categories	Feeder-type categories (four).	**Feeder-type categories (four), with definitions updated to be consistent with those in the revised STPIS.**
3.4 Performance during significant events: included or excluded?	Performance on major event days (MEDs) excluded from underlying performance using the IEEE method applied to the distribution system.	Continue: no change.
3.5 Standard of endeavour	Best endeavours.	Performance targets will continue to be of a 'best endeavours' nature. **'Best endeavours' explanations only required in instances where performance is beyond a 'reporting threshold'.** Then, SA Power Networks must report directly to the public on how it has applied its best endeavours, with reference to a Monitoring, Evaluation Compliance Strategy.
3.6 Other exclusions: revised to be consistent with STPIS reporting	Outages caused by transmission or generation failure, and momentary interruptions less than one minute.	Aligned with exclusions in the revised STPIS, which include a change in the momentary interruption definition to less than three minutes.
3.7 Restoration targets introduced	n/a	Introduce restoration time targets for each feeder category, set to maintain current performance. **Targets set for how much of the customer base experiences outages longer than two hours, and outages longer than three hours.**
4.1 Continuation of GSL payments for network reliability	Duration and frequency GSL payments.	Continue GSL payments for network reliability, swap duration payments for total duration payments.
a) Duration payments will be removed	Five levels of duration payments for one-off outages. Values range from \$100 (12 to 15 hours) to \$605 (48 hours +).	Discontinue, replace with total annual duration payments and restoration targets.
b) Total annual duration payments will be introduced	n/a	Introduce payments for total annual outage duration, to apply at the end of each financial year. Three levels of payment: > 20 and ≤ 30 hours, \$100; > 30 and ≤ 60 hours, \$150; > 60 hours, \$300.

Section/element	Current arrangement	Arrangement for 2020 - 2025
c) Frequency payments will be simplified	Three levels of frequency payments that apply at the end of each year. Values are $100 for more than nine but less than twelve outages, $150 for more than 12 but less than 15 outages, and $200 for more than 15 outages.	Consolidate frequency payments: one level of payment: $100 for more than nine outages per annum.
4.2 Late attendance at appointments	A payment of $25 when SA Power Networks is more than 15 minutes late for an appointment.	Discontinued.
4.3 Timeliness of new connections	A payment of $65 per day (to a maximum of $325) applies when the connection is not made on an agreed date, or within six business days if no date is agreed.	Continue: will apply to provision of infrastructure to enable a connection for a customer's new supply address rather than connection of a customer's new supply address.
4.4 Repair of faulty street light(s)	Payment of $25 for each five/ten day period where repair takes longer than five/ten days (metro/non-metro).	Continue repair of faulty street light GSL payment. No change. The Commission recognises design of this payment might be usefully improved, but will not make amendments at this time.
5.1 Telephone responsiveness standard	85% of calls responded to within 30 seconds.	Continue: definition revised.
5.2 Written responsiveness target	95% of enquiries responded to in five business days.	Continue: will apply to written enquiries generally, rather than by letter, fax or email.
5.3 SMS communication standard	n/a	No requirements for how SA Power Networks provides information about outages by SMS.
5.4 Communication quality measure: for monitoring	n/a	Require SA Power Networks to report on a communication quality measure, as agreed with the Commission, initially for reporting only.
6.1 Reporting on ten regional categories	Reporting on seven regions	Require reporting on performance for ten regional categories, those proposed as the basis for network reliability standards in the draft decision.
6.2 Normalising regional performance data	Not specified by the Commission	Specified from 1 July 2020, with the Commission to develop and consult publicly on an acceptable methodology ahead of 1 July 2020.
6.3 Reporting on low reliability feeders	Low reliability feeders have USAIDI twice as high as the target for that feeder class for two consecutive financial years.	Low reliability feeders have USAIDI twice as high as the mean for that region for two consecutive financial years.

Section/element	Current arrangement	Arrangement for 2020 - 2025
6.4 SA Power Networks will report directly to its customers	Commission publishes a series of reports on SA Power Networks' performance.	SA Power Networks publishes its own performance reports, with oversight and scrutiny by the Commission.
6.5 Annual regional reports	n/a	Reporting includes a set of annual regional reports, for ten regions.
6.6 SA Power Networks must publish time-series data	The Commission publishes time-series data on its website.	Require SA Power Networks to provide and publish time-series data that is consistent with the overall revised framework (from 2005-06 onwards).

1 Introduction

The Essential Services Commission (**Commission**), established under the Essential Services Commission Act 2002 (**ESC Act**), is the independent economic regulator of essential services in South Australia. In undertaking its regulatory functions, the Commission's primary objective is the protection of the long-term interests of South Australian consumers with respect to the price, quality and reliability of essential services.[2]

SA Power Networks is the owner and operator of South Australia's main electricity distribution network that connects over 890,000 customers to the national electricity grid.[3] SA Power Networks' distribution network links the transmission network, which supplies electricity from larger generators, with customers. It also supports growing amounts of small-scale generation connected directly to the distribution network.

The Commission and the Australian Energy Regulator (**AER**) jointly undertake economic regulation of the electricity distribution services provided by SA Power Networks. The Commission's role is to set and review the reliability standards that apply to SA Power Networks.

The AER's role includes making five-yearly revenue determinations for SA Power Networks, and administering the Service Target Performance Incentive Scheme (**STPIS**), which provides incentives for SA Power Networks to improve average performance, and maintain those improvements (see Box 1).[4]

The Commission's power to set and review SA Power Networks' reliability standards is established by the Electricity Act 1996 (**Electricity Act**), and is supported by the provisions of the Australian Energy Market Agreement, National Electricity Law, National Electricity Rules, National Energy Retail Law and National Energy Retail Rules.[5]

Under the Electricity Act, SA Power Networks is required to hold a licence authorising it to operate the electricity distribution system in South Australia. The Commission is the licensing authority for the purposes of the Electricity Act. The Electricity Act mandates certain licence terms and conditions, while providing the Commission with the discretionary power to include additional licence terms and conditions.

The Electricity Distribution Code version 12.1 (**Code**) establishes the reliability standard framework that applies to SA Power Networks, and compliance with the Code forms a condition of SA Power Networks' distribution licence. The reliability standard framework has four main elements: network reliability standards and performance targets, a Guaranteed Service Level (**GSL**) scheme, customer service standards, and monitoring and reporting requirements.

The current five-year revenue determination period ends on 30 June 2020. The Commission has conducted this review of the reliability standard framework that applies to SA Power Networks, ahead of the 1 July 2020 – 30 June 2025 regulatory period (**Review**). This is the Commission's final decision.

2 Essential Services Commission Act 2002, section 6(a).

3 890,000 represents the number of meters (National Meter Identifiers) active in the last year. A smaller number of meters – approximately 860,000 – are active at any one point in time.

4 The Australian Energy Regulator assesses SA Power Networks' revenue proposal with reference to national and state requirements, including the reliability standards established by the Commission.

5 The Australian Energy Market Agreement provides for State and Territory Governments to retain responsibility for developing service reliability standards to ensure network security and reliability. The Commission is responsible for developing, implementing and administering the jurisdictional service standards for SA Power Networks.

Box 1: Jurisdictional reliability standards and the Service Target Performance Incentive Scheme

The Australian Energy Market Agreement allows jurisdictions to maintain their ability to set service reliability standards.[6] In South Australia, there is an additional requirement that minimum standards of service are at least equivalent to the levels that existed during the year prior to 11 October 1999.[7]

The National Electricity Rules require the Australian Energy Regulator (**AER**) to ensure that a distributor's revenue allowance is set to allow it to deliver against any jurisdictional service standards for maintaining network reliability.[8]

The AER's Service Target Performance Incentive Scheme (**STPIS**) is the main financial incentive mechanism in the broader service standard framework for SA Power Networks.[9] It has applied since 2010, when it replaced the Commission's Service Incentive Scheme.

The purpose of the STPIS is to provide incentives for distributors to improve and maintain reliability performance where improvements are valued by customers. It operates concurrently with jurisdictional service standards and Guaranteed Service Level (**GSL**) schemes and is administered by the AER.

The STPIS aims to ensure that service levels do not fall as distributors strive to achieve efficiency gains, typically associated with a reduction in expenditure. It balances other AER mechanisms that incentivise reduced expenditure, but do not take into account network performance.

The STPIS has four components: reliability of supply, quality of supply, customer service and a GSL scheme. The AER decides how the STPIS will apply to each distributor as part of the revenue determination process.

As it currently applies to SA Power Networks, the STPIS relates to reliability of supply (duration and frequency of interruptions, for distribution feeder categories) and customer service (telephone answering).[10] Targets are set as an average of five years' performance. As a jurisdictional GSL scheme is in place, the STPIS GSL scheme does not apply.[11]

Currently, an incentive of up to five percent of SA Power Networks' total revenue allowance applies to performance against these parameters. The incentive rewards SA Power Networks for improving performance, and penalises SA Power Networks for declining performance (also by up to five percent).

In November 2018, the AER released a revised STPIS, which will apply to SA Power Networks in the 2020 – 2025 period.

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6 Australian Energy Market Agreement, Annexure 2.

7 Electricity Act 1996, section 23(1)(n)(v).

8 National Electricity Rules, section 6.5.6 (forecast operating expenditure) and section 6.5.7 (forecast capital expenditure).

9 National Electricity Rules, section 6.6.2.

10 Australian Energy Regulator, *SA Power Networks Determination 2015 – 2020 Final Decision Attachment 11 – Service Target Performance Incentive Scheme*, October 2015, pp. 10-11, available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020/final-decision.

11 Australian Energy Regulator, *Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme Version 2.0*, November 2018, section 6.1(a), available at https://www.aer.gov.au/system/files/AER%20-%20Service%20Target%20Performance%20Incentive%20Scheme%20-%20for%20publication%20-%20clean%20-%20no%20tracked%20changes%20-%2014%20Nov%202018.pdf.

1.1 Review objective

The Commission has sought to define reliability levels that are valued by customers. This task supports the broader economic regulation of SA Power Networks, which the Commission jointly administers with the AER. The broader economic regulatory framework supports and challenges SA Power Networks to:

- provide services at the lowest sustainable price for the quality and reliability levels valued by customers, and
- have in place sound and long-term asset management and financing strategies and delivery, which support the provision of those services for customers of today and tomorrow.

In defining reliability standards that customers value, the Commission's primary objective is that of section 6 of the ESC Act: the protection of the long-term interests of South Australian consumers with respect to the price, quality and reliability of essential services.[12]

In pursuing this primary objective, the ESC Act requires the Commission to have regard to the need to:

i. promote competitive and fair market conduct; and
ii. prevent misuse of monopoly or market power; and
iii. facilitate entry into relevant markets; and
iv. promote economic efficiency; and
v. ensure consumers benefit from competition and efficiency; and
vi. facilitate maintenance of the financial viability of regulated industries and the incentive for long-term investment; and
vii. promote consistency in regulation with other jurisdictions.

The most relevant of these factors are the need to: promote economic efficiency, and ensure consumers benefit from competition and efficiency. The Commission has considered this in terms of seeking to develop reliability standards that customers value.

Developing reliability standards that customers value requires assessing the trade-off between price and reliability. Higher reliability levels may provide extra benefits to customers, but also raise costs and prices.

In competitive markets, the price-service mix is optimised by consumers choosing the service they prefer, given the price. As monopolies, electricity distributors such as SA Power Networks are not subject to competitive forces in relation to the price and quality of the distribution services they provide. Coupled with revenue regulation, service standard regulation seeks to determine efficient service levels for distribution services, given the absence of a competitive market.

With respect to the trade-off between price and reliability, it is useful to emphasise that the reliability experienced by customers is not driven solely by the reliability of the distribution network.

[12] In the December 2017 Objectives and Process paper, the Review objective was defined as 'to establish reliability standards that require SA Power Networks to provide distribution services valued by customers at an acceptable cost'. In its submission to the December 2017 Objectives and Process paper, the South Australian Council for Social Services argued that that it is not necessary to have an objective for the Review that is separate from the objective of the ESC Act. The Commission accepts this comment, and has reframed the original objective.

It is also determined by the reliability of the transmission network, and reliability of generation. Nor are distribution costs the sole component of electricity prices, or electricity price increases.[13]

The distribution network transports electricity from exit points on the transmission network to customers, and connects distributed generators to customers. SA Power Networks' contribution to reliability is to have the distribution network in operating order so this can occur.

Resolving the trade-off between price and reliability means identifying an acceptable level of network availability. This requires assessing the costs of delivering alternative reliability outcomes against customers' willingness to pay for that service.

The trade-off must be assessed in the context of South Australia's 'state-wide pricing' arrangements. For customers who consume less than 160MWh of electricity each year, government provision for state-wide pricing means the costs of distribution services are shared amongst all customers.[14] This tempers the fact that the cost of providing distribution services is highly dependent on location.[15]

The benefits of promoting consistency in regulation with other jurisdictions has also been considered. In particular, the Commission has sought to understand the interaction between its regulatory framework and the AER's various functions, schemes and decisions. The decision to align definitions, wherever possible, and work with the financial incentives and penalties provided by the revised STPIS are examples of where the Commission considers South Australian customers will benefit from consistency with other jurisdictions.

While facilitating maintenance of the financial viability of regulated industries and the incentive for long-term investment is also a relevant consideration, SA Power Networks' marginal expenditure on meeting jurisdictional reliability standards is low, and the scale of long-term investment for reliability modest. The Commission estimates that without specific investment to maintain jurisdictional reliability standards, average reliability would decline by less than one per cent, and reduce a typical annual residential electricity bill by approximately $2 per annum over the 2020 – 2025 period (for further detail, see section 3.1.2).[16]

1.2 Review process

This Review began in 2017, at the same time as SA Power Networks began customer engagement to inform its revenue proposal for the 2020 – 2025 period.[17] A broad evidence base has been used to reach this final decision. The evidence base has included:

- submissions in response to the draft decision published in August 2018, which are available on the Commission's website

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13 In relation to reliability, in 2016-17, half of all time off supply was due to transmission and generation outages. In relation to price, distribution costs account for 26.2 per cent of a typical residential customer's annual electricity bill. Other components are generation and retail (50.3%), Goods and Services Tax (9.1%), transmission (7.0%), green and energy efficiency scheme costs (3.4%), photovoltaic feed-in-tariffs (2.6%) and metering (1.4%).

14 State-wide pricing applies for customers with annual consumption less than 160 MWh. Section 35B of the Electricity Act provides for the Treasurer to make an Electricity Pricing Order. State-wide pricing provisions were established in the Electricity Pricing Order implemented on 11 October 1999, as summarised in the South Australian Government Gazette, p. 1471.

15 In general, costs are higher to provide services to customers in areas with low customer density. If network charges reflected locational costs, charges would double for many rural customers – see SA Power Networks, *Pricing Proposal 2016-17*, 10 June 2016, p. 25, available at https://www.aer.gov.au/system/files/AER%20approved%20-%20SA%20Power%20Networks%202016-17%20Annual%20Pricing%20Proposal%20-%208%20June%202016_0.pdf.

16 Based on ongoing expenditure of $37 million pa to maintain jurisdictional reliability standards. Avoiding this expenditure would reduce the cost for a typical annual residential bill by $2.01, assuming a 50-year asset life, and a discount rate of seven percent.

17 The National Electricity Rules require SA Power Networks to engage with its customers directly and demonstrate how customer concerns have been taken into account in developing its revenue proposal for the Australian Energy Regulator. SA Power Networks conducted its customer engagement program to understand the expectations, views and priorities of its customers to inform its 2020-2025 revenue proposal. The scope of the program extends beyond network reliability. The Commission has observed and had oversight of the program.

- submissions in response to an Objectives and Process paper published in December 2017, also available on the Commission's website
- SA Power Networks' customer engagement program. Details of the engagement, including several reports, are available at www.talkingpower.com.au
- direct consultation with stakeholders
- issues identified through performance monitoring and reporting
- workshops with SA Power Networks[18]
- discussions with other regulators
- relevant national benchmarking
- complaints data from the Energy and Water Ombudsman SA, and
- economic assessment of reliability standard options.

Each of these elements is an input to the Review; the Commission has not relied on any one single input in making this decision. The Commission has considered evidence from each source, and weighed it in the context of the statutory requirements.

The Commission has been assisted by the submissions it has received through the Review process. The issues raised by stakeholders through the consultation period have been carefully considered and, where relevant, certain arguments and submissions have been mentioned in the text, either by direct quotation or by reference to themes or arguments, to assist stakeholders to understand the proposed positions that have been reached.

However, a failure to reference an argument or submission does not mean that it has not been taken into account in reaching the final positions. While not all of the positions put in the submissions have been adopted, all submissions have informed the consideration of each of the relevant issues and the competing viewpoints.

1.3 Outline of this decision

Next, a short summary of SA Power Networks' performance is provided. Then, the remainder of the decision is organised around each of the reliability standard framework's four main elements: network reliability standards and performance targets (section 3), the GSL scheme (section 4), customer service standards and targets (section 5) and reporting and monitoring (section 6). Each of these sections outlines the Commission's decisions, and presents the rationale for changes to apply from 1 July 2020.

[18] The Commission held a series of workshops with SA Power Networks in October 2017, with the objective of developing options for revised reliability standards that respond to the themes raised in customer engagement, issues identified through performance monitoring and reporting, and the Commission's direct consultation with stakeholders. Members of SA Power Networks' regulatory, reliability, customer service, and customer engagement teams attended the workshops. Senior managers in the Commission and SA Power Networks attended both an initial session to agree on the scope of the workshops and a final session to discuss the results of those workshops.

2 SA Power Networks’ performance

The underlying reliability of the distribution network from 2005-06 to 2017-18 has been reasonably consistent, albeit that some areas were adversely affected in 2016-17 by severe weather (Eastern Hills and Eyre Peninsula) and equipment failure (Central Business District (CBD) feeders).

On a feeder-type category basis, performance from 2005-06 to 2017-18 has been reasonably consistent for urban feeders and has steadily improved for CBD, rural short and rural long feeders. With regard to recent performance, rural short feeders did not meet performance targets in 2016-17, and CBD feeders did not meet performance targets in 2016-17 or 2017-18.

On a reporting region basis, performance from 2005-06 to 2017-18 has been reasonably consistent across regions within the State. Performance declined in the Eastern Hills and Fleurieu Peninsula, and Upper North and Eyre Peninsula in 2016-17 due to the impact of severe weather, and in the Adelaide Business Area in 2016-17 and again in 2017-18 due to equipment failure.

The Commission currently reports on performance annually and quarterly. Further detail on performance for the whole distribution system, each feeder-type category and reporting region is available in the annual regulatory performance reports and quarterly operational performance and monitoring reports (see www.escosa.sa.gov.au).

2.1.1 Looking behind the averages

The trends discussed above are for average (mean) performance, which is the basis of the Commission’s network performance targets. Averages do not reflect the experience of individual customers: some customers experience performance that is better than average and some experience performance that is below average (see Box 2).

Variation in performance around the mean is normal in electricity distribution networks, reflecting the generally random nature of unplanned interruptions and that the network has pockets of low customer density, where cost of reliability for each customer is high because of limited economies of scale.

Historically, SA Power Networks’ reliability standards have focused on the experience of customers not well served by broad targets for average performance.

This is evidenced in continued reporting on low reliability feeders[19], setting reliability standards for individual regions prior to 2015, and by including performance for worst served customers as the main parameter in the Service Incentive Scheme (established by the Commission for the 2005 – 2010 period, prior to introduction of the STPIS).

[19] Low reliability feeders are currently defined as those with USAIDI twice as high as the target for that feeder class for two consecutive financial years.

Box 2: How does reliability vary within each feeder category?

There is variation in the number of customers served by each feeder – an individual feeder may serve fewer than 100 customers or more than 3500 customers.

This analysis examines the Unplanned System Average Interruption Duration Index (USAIDI) of 1631 individual SA Power Networks distribution feeders for the 2010-11 to 2017-18 period.[20]

For urban, short rural and long rural feeders, mean USAIDI is contrasted with USAIDI at the 50th percentile (half of all feeders have USAIDI below this point), and USAIDI at the 95th percentile (five percent of all feeders have USAIDI beyond this point).

Figure 1 illustrates what this means for customers by showing the number of customers served by feeders in each percentile category (rather than the number of feeders in each percentile category).

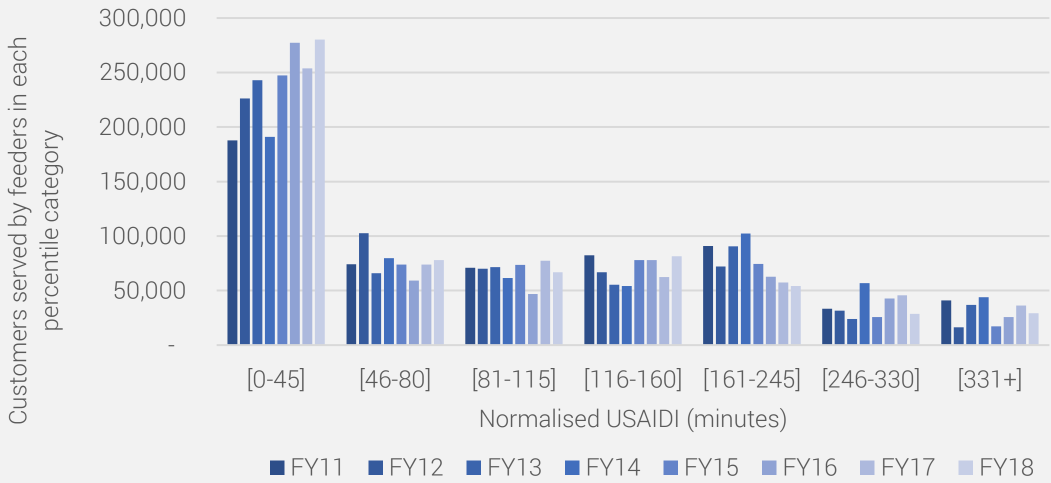
This provides an illustration, but is not a perfect representation because of variation in the number of customers served by each feeder. For example, though half of all feeders have USAIDI below the 50th percentile, this does not mean that half of all customers have USAIDI below this point.

Short rural feeders – Average (mean) annual duration of interruptions for short rural feeders across the period was 194 minutes. However, half of all short rural feeders had interruptions of 130 minutes or less, and five percent had interruptions of 905 minutes or more.

Long rural feeders –The average annual duration of interruptions for long rural feeders across the period was 281 minutes. However, half of all long rural feeders had interruptions of 190 minutes or less, and five percent had interruptions of 1385 minutes or more.

Urban feeders – The average annual duration of interruptions of urban feeders across the period was 107 minutes. Half of all urban feeders had interruptions of 45 minutes or less, and five percent had interruptions of 331 minutes or more (as shown in Figure 1, together with change over time).

Figure 1: Average annual duration of interruptions (minutes) 2010-11 to 2017-18[21]



[20] SA Power Networks has 1727 distribution feeders. Feeders that straddle the border of the Adelaide Business Area and Adelaide Metropolitan Area were excluded from this analysis. Data are normalised. The impact of outages caused by loss of transmission or generation supply, and significant events (defined as major event days) is excluded.

[21] The first category represents performance up to the 50th percentile, with the following categories representing the 60th, 70th, 80th, 90th and 95th percentiles, and the final category representing performance beyond the 95th percentile. When data is prepared with additional categories below the 50th percentile, the distribution remains skewed to the right. The reliability of feeders above the 50th percentile varies much more than that of feeders below the 50th percentile.

2.1.2 Performance compared with relevant national benchmarking

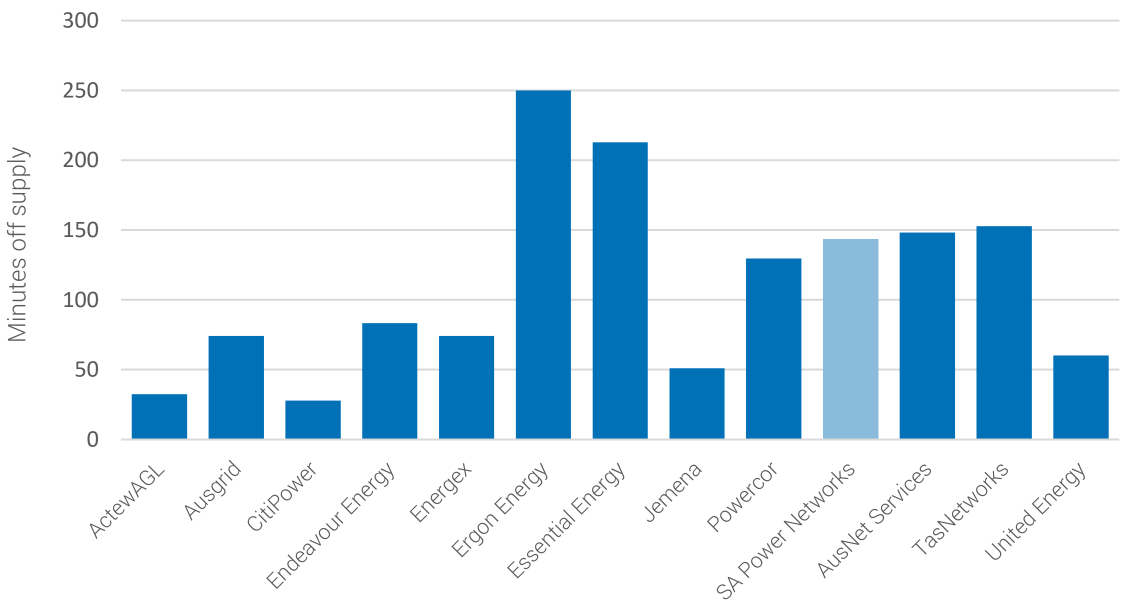
The Commission is required by section 23(1)(n)(v) of the Electricity Act to have regard to relevant national benchmarks in establishing reliability standards. The AER publishes an annual benchmarking report that covers all Australian electricity distributors.[22]

It includes benchmarking of electricity supply reliability, using average number of minutes off supply per customer per annum and the average number of interruptions per customer per annum. These reliability performance measures are strongly related to customer density (number of customers per kilometre of line), which varies across distributors.

In recent analysis, the Australian Energy Market Commission (**AEMC**) used distributor data to demonstrate that grid supply in low-density areas can be less reliable (and more costly) than in high-density areas. The AEMC noted that even greater extremes would be expected if data were available at higher resolution (ie within each distributor's network).[23]

SA Power Networks has customer density of around ten customers per kilometre of line. The most comparable distributors are Powercor (Western Victoria, 12 customers/km), TasNetworks (14 customers/km), and AusNet Services (Eastern Victoria, 18 customers/km).[24] SA Power Networks performs well in comparison to these distributors. Benchmarking results are shown in Figure 2 and Figure 3.[25]

Figure 2: Average minutes off supply per customer across Australian electricity distributors (2013 – 2017)



Source: Australian Energy Regulator, *Distribution Network Service Provider Annual Benchmarking Report*, p. 53.

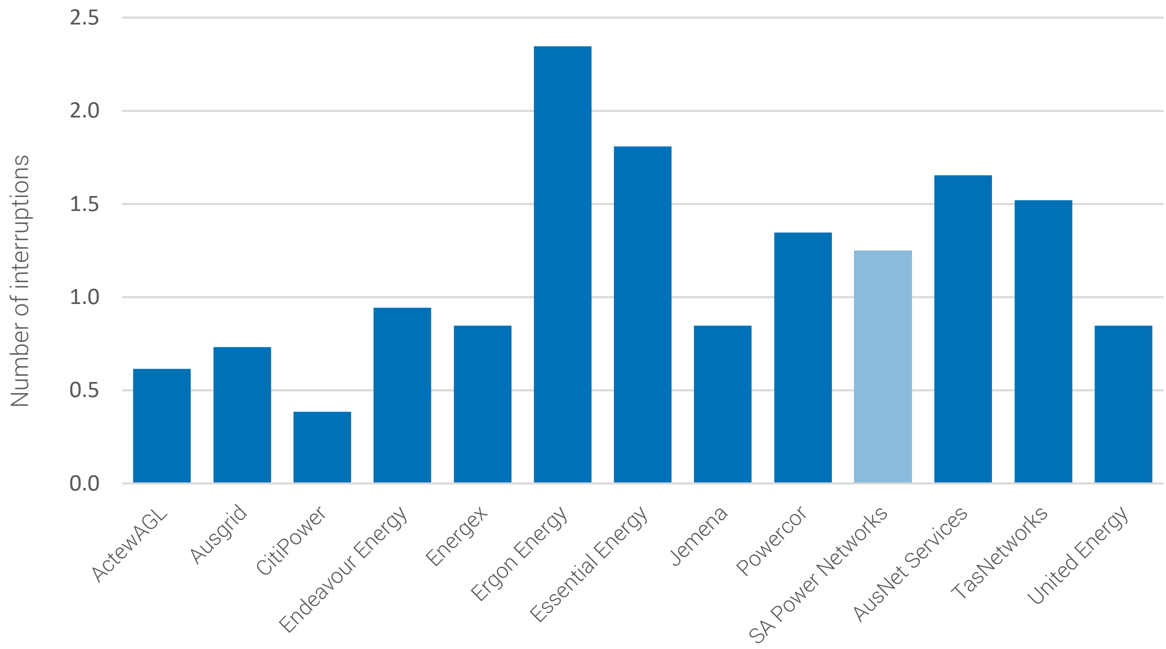
22 Australian Energy Regulator, *Distribution Network Service Provider Annual Benchmarking Report*, November 2018, available at https://www.aer.gov.au/system/files/AER%202018%20distribution%20network%20service%20provider%20benchmarking%20report%20_0.pdf.

23 Australian Energy Market Commission, *National Electricity Amendment (Alternatives to grid-supplied network services) Rule*, 2017, pp. 15-18, available at https://www.aemc.gov.au/Rule-Changes/Alternatives-to-grid-supplied-network-services.

24 Australian Energy Regulator, *Distribution Network Service Provider Annual Benchmarking Report*, p. 53-54.

25 Data excludes the effects of major events, planned outages and transmission outages, and is comparable with the Commission's data on SA Power Networks' performance.

Figure 3: Average number of interruptions per customer across Australian electricity distributors (2013 – 2017)



Source: Australian Energy Regulator, *Distribution Network Service Provider Annual Benchmarking Report*, p. 54.

3 Average annual network reliability standards

This section addresses the first of the reliability standard framework's four main elements: average annual network reliability standards.

The Code currently sets average annual network reliability standards for each of four feeder-type categories: CBD, urban, short rural and long rural.

The standards comprise two parts.

First, targets are established based on historical performance. These are set for average duration and frequency of interruptions. Targets relate to normalised performance, where outages caused by loss of transmission or generation supply and the impact of major event days (**MEDs**) are excluded from performance data.

Second, if a target is not met, the Commission will assess if SA Power Networks has used its 'best endeavours' to achieve the target. Best endeavours is defined as to act in good faith and use all reasonable efforts, skills and resources. If SA Power Networks is assessed as using its best endeavours, the reliability standard is met.

3.1 Overall level of service: maintain, reduce or improve?

The final decision is to set network reliability targets to maintain reliability at current levels.

For the 2015 – 2020 period, network reliability targets were set to maintain reliability, as the average of five years' performance prior to the start of the regulatory period. For 2020 – 2025, network performance targets will be again set to maintain reliability, as the average of either five or ten years' performance prior to the start of the regulatory period.

Where performance has improved over time, targets based on the most recent five years' performance will demand a higher level of reliability than targets based on ten years' performance. Conversely, where performance has declined over time, targets based on the most recent five years' performance will demand a lower level of reliability than targets based on ten years.

The Commission will decide whether to set performance targets as the average of five or ten years' performance in late 2019, at the same time it sets performance targets. In selecting whether to set performance targets as the average of five or ten years' performance, the Commission will consider whether the difference is material. Then, in defining 'current levels' the Commission will have regard to:

- maintaining reliability outcomes, and
- mitigating the impact of variation in performance.

3.1.1 Submissions to draft decision

The SA Power Networks submission supports the draft decision to maintain reliability performance at current levels, and submits this reflects customer satisfaction with current reliability levels. Its view is that if the Commission 'were to adopt region-based standards, a 10-year average should be used to establish the targets. Further, the targets should be rounded up to the nearest five minutes or 0.05 interruptions.'[26]

[26] SA Power Networks submission to the Review draft decision.

In its earlier submission to the Review's Objectives and Process paper, SA Power Networks discussed recent CBD feeder performance, which did not meet the performance target in 2016-17 or 2017-18. SA Power Networks argued that future targets for this area should reflect its 'inherent stability', which is reflected in 'historic performance over a period longer than five years'. [27]

SACOSS is 'strongly supportive' of the Commission's decision to maintain reliability at current levels. It accepts the finding that there is no clear economic benefit in setting targets to improve performance. Its view is that maintaining current levels of service is consistent with feedback it has received, that price is of primary concern to customers.

Business SA supports the approach of understanding willingness to pay for reliability. It asks that the Commission be mindful of recent electricity price rises in determining if and how to increase any of SA Power Networks' reliability standards. It raises some specific comments on the customer survey and economic assessment used to support this decision point. These are that:

- The result from the customer survey that 73 percent of customers are satisfied with reliability should be more clearly contrasted with the 2013 survey result, which showed 88 percent were satisfied. Business SA submits this decline should be 'cause for concern and necessitate a sharp focus for [the Commission] setting the reliability standards to a level which is satisfactory and meets community expectations, including that of business.'
- The scenario of a ten percent reliability improvement for low reliability feeder customers had a net benefit in the cost-value assessment commissioned for the Review.[28] Business SA submits that the distribution of customer willingness to pay (with many customers not willing to pay anything at all) is not enough reason to disregard this result.

  Further, results for this scenario may have been different if costs were presented as the bill increase that would arise given state-wide pricing, rather than as the full cost of improvements spread only across low reliability feeder customers. (This presentation of costs is explained further in Appendix 3, under the subheading 'How were costs presented to customers?').
- The Commission should 'sense check' its value of customer reliability (**VCR**) analysis using the new AER VCRs that are due in December 2019.
- Reasons for not requiring SA Power Networks to invest in low reliability areas where off-grid or distributed energy technologies might 'supersede network investments' are likely sound, but should be further described in the final decision.

These comments are each addressed as part of the rationale presented in section 3.1.2.

3.1.2 Rationale

The final decision to set network performance targets to maintain reliability at current levels of performance is justified for three reasons:

- A reduction on long-term average performance would not meet requirements of the Electricity Act, and would yield limited cost savings.
- Customers have expressed overall satisfaction with current levels of reliability.
- There is no clear economic benefit in setting targets to improve reliability performance.

[27] SA Power Networks submission to the Review Objectives and Process paper.

[28] The Commission engaged consultants Oakley Greenwood and Wallis Market Research to conduct a contingent valuation study for the Review (with questions incorporated in the customer survey), to quantify the benefits of a number of reliability improvement scenarios, and then complete a cost-value assessment. A final project report was published alongside the draft decision. (See Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages*).

These reasons are each detailed further below.

Performance targets cannot be set to reduce reliability performance

In SA Power Networks' customer engagement process, some people expressed a preference to accept reliability reductions in order to reduce costs.[29] Further, the South Australian Council of Social Services (SACOSS) submission to the Commission's Objectives and Process paper asked for reduced reliability to be included in any economic assessment, on the basis it may deliver cost savings.

Ultimately, scenarios for reducing reliability performance targets were not assessed, as a reduction would not meet requirements of the Electricity Act. Section 23(1)(n)(v) of that Act requires standards to be set to maintain reliability relative to 1998-99 levels. Reliability has not definitively improved since then, so the Commission may not set long-term network standards to reduce reliability. This is discussed further in Appendix 1.

Although legal requirements prevent setting network standards to 'reduce' reliability, the Commission nevertheless considered whether doing so would deliver cost savings. It found that, in the current environment of electricity consumption and demand in South Australia, marginal expenditure on network reliability is low and hence reduced standards would not deliver meaningful cost reduction for consumers.

SA Power Networks' total expenditure to maintain jurisdictional reliability standards will be $37 million over the 2015 – 2020 period. It has indicated that expenditure associated with maintaining reliability at current levels would be similar over the 2020 – 2025 period. [30,31] Without this investment, average reliability would decline by less than one per cent, and a typical residential electricity bill would be reduced by approximately $2 per annum over the period.[32]

With the exception of this $37 million, SA Power Networks' expenditure is, in the first instance, identified as being required to meet other legal and regulatory requirements, including the suite of National Electricity Rules, and the design, technical, and safety standards brought together in annual Safety, Reliability and Maintenance Technical Management Plans. The Commission recognises that individual expenditure items often serve dual purposes – for example, repair and replacement deliver both safety and reliability outcomes.

Contingent valuation results

Contingent valuation is an economic valuation technique for quantifying the value of non-market goods or services, such as reliability improvements, for input into economic assessment.

The Commission engaged consultants Oakley Greenwood and Wallis Market Research to conduct a contingent valuation study through the customer survey undertaken for this Review. (Detail on this method, reasons for selecting it, and results are discussed further in Appendix 3, and in the Oakley Greenwood report that accompanied the draft decision).

[29] For example, in the Directions Workshops conducted by SA Power Networks in 2017, just under 20 percent of customers indicated a preference for reduced investment in network reliability and resilience.

[30] In SA Power Networks' current revenue determination, $27 million ($2014-15) over five years is identified for maintaining jurisdictional standards. (See Australian Energy Regulator, *SA Power Networks Determination 2015 – 2020 Final Decision Attachment 6 – Capital Expenditure*, 2015, p. 42, available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020/final-decision).

[31] The SA Power Networks Draft Plan, released in August 2018, proposes $37 million to 'maintain supply reliability expenditure at current levels to meet our ongoing average reliability targets'. (See SA Power Networks, *2020 – 2025 Draft Plan*, 2018, available at https://www.talkingpower.com.au/38336/documents/84356). This comprises $27 million for work on power line assets, as identified in the current revenue determination, and $10 million for reliability protection management within substations. Both are ongoing programs (that is, are a continuation of work in the 2015 – 2020 period). Total expenditure to maintain jurisdictional standards will remain steady.

[32] The cost for a typical annual residential bill would be $2.01 assuming a 50-year asset life, and a discount rate of seven percent.

Results show that only one reliability improvement scenario has a net benefit: an average 10 percent reduction in interruption frequency (associated with a 90-minute annual average reduction in outage duration) for the 27,000 customers on low reliability feeders. This scenario has a net annual benefit of $1.9 million, equivalent to 0.05 percent of SA Power Networks' recoverable revenue for the current 2015 – 2020 period.

The benefits arise from a minority of customers. Two-thirds of the 27,000 customers on low reliability feeders who would benefit directly from these improvements are not willing to pay anything at all for the improvement. This is consistent for both residential (62 percent) and business customers (66 percent).[33] A potential explanation is that some low reliability feeder customers may have contingency plans (including on-site generation).

Likewise, there are customers who would not benefit directly who do not want to subsidise this improvement. Some customers in metropolitan areas are not willing to subsidise improvements for low reliability feeder customers (54 percent of residential, and 52 percent of business), nor are some customers in non-metropolitan areas (38 percent of residential, and 52 percent of business).[34]

The Commission notes Business SA's position, that the distribution of customer willingness to pay is not enough reason to disregard the fact that this scenario shows an overall net benefit. There were three reasons why the Commission did not make a decision based on the contingent valuation study showing a net benefit for this scenario. They were: the distribution of customer willingness to pay, the results of the VCR analysis (discussed in the next section), and the possibility that emerging technologies may supersede network investment on these feeders.

Many low reliability feeders have low customer density or are at the edge of the network. In these situations, off-grid supply may be the most cost-effective option for improving reliability. The Clean Energy Council's submission to the draft decision notes two estimates of savings that would arise from using off-grid supply instead of replacing network assets.[35] Though an estimate of savings is not available for South Australia, the scale of potential savings illustrates why the Commission has hesitated to require network investment through the 2020 – 2025 period.

The Commission acknowledges Business SA's observation that customers on low reliability feeders may have responded differently (for example, been willing to pay more) if they were presented with costs as the bill increase that would arise given state-wide pricing, rather than being presented with full cost of improvements spread only across low reliability feeder customers.

The reason why customers were presented with the latter was that the objective of the study was to identify willingness to pay in the absence of a cross subsidy. This more accurately represents the value attributed to the service level change, noting that many customers would be willing to allow others to cover the cost of service improvements that benefit them.

A majority of customers are satisfied with current levels of reliability

In the customer survey[36] commissioned for this Review, the majority of customers (73 percent) were either satisfied or very satisfied with reliability of electricity supply to their home or business. A further 15 percent were neither satisfied nor dissatisfied, with 12 percent dissatisfied or very dissatisfied.[37]

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33 Error bands for these results, at a 95 percent confidence level, are 6 percent for residential responses and 11.8 percent for business responses.

34 Note the error bands that apply to these results, which are set out in Appendix 3, Table 13.

35 Clean Energy Council submission to the Review draft decision.

36 Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages.*

37 Error bands for these results, at a 95 percent confidence level, are 3.1 percent for residential responses and 5.6 percent for business responses.

Levels of satisfaction have declined in relation to levels reported in in 2013 (88 percent), 2007 (84 percent) and 2003 (85 percent).[38]

Metropolitan customers reported higher satisfaction than non-metropolitan customers and customers on low reliability feeders. These disaggregated results are shown in Table 2.

Table 2: Levels of satisfaction with reliability of electricity supply to home or business, for metropolitan, non-metropolitan and low reliability feeder customers

	Very satisfied	Satisfied	Neither	Dissatisfied	Very dissatisfied	Refused or don't know
Metropolitan – residential	25%	54%	16%	4%	1%	0%
Metropolitan – business	18%	53%	13%	14%	3%	0%
Non-metropolitan – residential	20%	49%	14%	14%	2%	0%
Non-metropolitan – business	20%	48%	16%	11%	5%	0%
Low reliability feeder – residential	9%	44%	27%	15%	6%	0%
Low reliability feeder – business	25%	54%	16%	4%	1%	0%

This question in the customer survey asked 'overall, how satisfied are you with the reliability of the electricity supply to your home or business?'.[39] It related to overall reliability outcomes, not performance of the distribution system.

In the 18 months before the survey was conducted (in May 2018), South Australia experienced several large-scale outages. These included the state-wide outage of 28 September 2016, storm-related outages in December 2016, and rotational load shedding on 8 February 2017. Two of these outages (28 September 2016 and 8 February 2017) occurred because of generation and transmission supply issues. The change in satisfaction levels must be understood in this context. That is, the level of satisfaction does not necessarily (or only) represent distribution system performance.

Business SA's submission to the draft decision notes the decline in customer satisfaction should be 'cause for concern and necessitate a sharp focus for [the Commission] setting the reliability standards to a level which is satisfactory and meets community expectations, including that of business.'

The Commission acknowledges that customer satisfaction has declined, and agrees that this is cause for concern. It also agrees with Business SA that this decline is not surprising in light of recent reliability events. While this broad customer satisfaction statistic is useful as a general guide in setting reliability standards, the Commission has been mindful that reliability experienced by customers is not driven solely by the reliability of the distribution network. It is also determined by the reliability of the transmission network, and reliability of generation.

Further, dissatisfaction does not necessarily translate directly into willingness to pay for improvements. The costs of delivering alternative reliability outcomes needs to be separately assessed against customers' willingness to pay for that service. As discussed below, the customer survey showed limited willingness to pay for reliability improvements.

38 Figures represent the proportion of customers reporting being either 'very satisfied' or 'quite satisfied' with their electricity supply reliability. The Commission conducted the 2003 and 2007 customer surveys, and SA Power Networks conducted the 2013 survey. There are limitations in comparing the results of these surveys, relating to question design and sample size.

39 Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages, Appendix 1, p. 4.*

No clear economic benefit in setting targets to improve performance

Two economic assessments of the value of setting targets to improve reliability performance have been completed as part of this Review. Results show no clear economic benefit in any of the scenarios examined.

Previously, the Commission has regarded broad levels of customer satisfaction and legal requirements in its decisions on whether to set network performance targets to reduce, improve, or maintain performance. The Commission's 2015 decision noted AEMC recommendations to have regard to economic assessment in the decision-making process.[40]

In this Review, economic assessments were completed for several cost-value scenarios (summarised in Appendix 2). All are scenarios for reliability improvements, with costs and reliability impacts provided by SA Power Networks. The baseline for these scenarios is maintaining reliability at current levels.

The scenarios are based on reducing interruption frequency (Unplanned System Average Frequency Duration Index, USAIFI) by one, five and 10 percent. Interruption frequency was chosen as the basis for the scenarios because it can be impacted directly and predictably by capital investment. When interruption frequency (USAIFI) is reduced, interruption duration (Unplanned System Average Interruption Duration Index, USAIDI) also falls.

Scenarios were constructed for reliability improvements for metropolitan customers, non-metropolitan customers, and customers on low reliability feeders (using the current definition, of feeders with twice the USAIDI for the respective feeder category, for two consecutive financial years). This design responded to:

- concerns raised in SA Power Networks' customer engagement about the difference in reliability experienced by metropolitan customers, non-metropolitan customers, and customers on low reliability feeders.
- the Commission's concern that design of the STPIS may through time inadvertently produce a decline in reliability in lower density areas, and the possibility of responding to this by tightening some performance targets.

The CBD was excluded from the cost-value scenarios. This was because performance targets for the CBD are already tight at USAIDI of 15 minutes. The Commission has separately considered the implications of recent performance in the CBD where USAIDI targets have been exceeded for two consecutive years (2016-17 and 2017-18), and implications of growth of the CBD beyond the Adelaide Business Area for establishing CBD performance targets (see section 3.1).

Benefits were quantified using two different methods: a contingent valuation study, commissioned for this Review based on results of the customer survey, and desktop analysis based on Australian Energy Market Operator (AEMO) estimates of value of customer reliability (VCR).

Assessments of the cost-value scenarios have explicitly examined the cost of providing specific types of service against the value customers place on that service. The results, which show no clear economic benefit in setting targets to improve reliability performance, are summarised below.

[40] Australian Energy Market Commission, *Review of the National Framework for Distribution Reliability Final Report*, 2013, available at http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-national-framework-for-distribution.

Value of customer reliability (VCR) analysis results

Value of customer reliability refers to the amount of money a customer would be willing to pay to avoid a supply interruption. The most recent set of values were prepared by AEMO in 2013-2014.[41]

For this Review, desktop analysis based on AEMO estimates of VCR was conducted. Detail on this method and results are discussed further in Appendix 3.

Though results using contingent valuation suggest a small economic benefit in setting targets to facilitate a 10 percent reduction in outage frequency for customers on low reliability feeders, these results are not mirrored in results of the VCR analysis. Using the VCR analysis, the same scenario has a net cost of $1.6 million.

The Commission has concluded that results of economic assessment show no clear economic benefit in setting targets to improve reliability performance. A strong net benefit from each method would have supported the case for setting targets to improve performance.

The Commission also considered the case for targeted improvements in specific regions, using VCR analysis of cost-value scenarios developed by SA Power Networks (included as Appendix 2). Results show small, but somewhat uncertain, net benefits for a one percent reduction in outage frequency in three regions, and net costs for other regions (detailed in Appendix 3). The Commission's view is that these are not high enough to justify targeted regional improvements.

The Commission acknowledges the limitations of using the AEMO estimates (see Appendix 3). It considers that robust VCR values are important, and will contribute to the review of VCR values currently being conducted by the AER[42] through that project's Consultative Committee.

The Commission also notes the Business SA recommendation that the VCR analysis be 'sense checked' using revised VCR values that are expected to be published by the AER in December 2019. However, as revised values are not yet available, they cannot be used to inform this final decision.

3.2 Measures of network reliability

The final decision is to continue to use measures of average duration and frequency of interruptions (measured as USAIDI and USAIFI) to set average annual network reliability standards.

Unplanned System Average Interruption Duration Index (USAIDI) expresses duration of unplanned interruptions as the average duration of interruption, in minutes, across all customers in a category, over a year.

Unplanned System Average Interruption Frequency Index (USAIFI) expresses frequency of unplanned interruptions as the average number of interruptions across all customers in a category, over a year.

3.2.1 Submissions to draft decision

None of the six submissions to the draft decision specifically address this decision point.

[41] Australian Energy Market Operator, *Value of Customer Reliability Project Page*, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

[42] Australian Energy Regulator, *Value of Customer Reliability Review Project Page*, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability-vcr.

3.2.2 Rationale

The final decision is to continue the existing arrangement, for three reasons.

First, output measures (like USAIDI and USAIFI) prescribe an outcome for customers and allow distributors (here, SA Power Networks) flexibility around how to direct investment to achieve that outcome. This means that the particular technical solution is not prescribed – it is for the business operator to determine, provided it meets the intended outcome at least cost — and so promotes efficiency and innovation.

Second, output measures are used commonly in Australia and overseas, are recommended in the AER Distribution Reliability Measures Guideline and are the basis of the STPIS.[43, 44]

Third, the Commission has used these measures historically. Continuing to do so ensures consistency and allows time series comparison.

There are a number of reliability output measures. For example, the AER Distribution Reliability Measures Guideline lists both planned and unplanned:

- SAIDI, System Average Interruption Duration Index
- SAIFI, System Average Interruption Frequency Index
- CAIDI, Customer Average Interruption Duration Index
- MAIFI, Momentary Average Interruption Frequency Index
- MAIFIe, Momentary Average Interruption Duration Index event, and
- Supply reliability levels experienced by the lowest-reliability customer.

The Commission has previously decided not to use CAIDI, which represents average interruption length for all customers who have interruptions.[45, 46] CAIDI closely reflects the experience of a power interruption for an individual customer. However, it does not represent the number of customers whose power stays on, and so does not reflect efforts by distributors to prevent interruptions occurring. In contrast, SAIDI and SAIFI translate the impact of interruptions to the whole customer group, and so reflect efforts to prevent interruptions.

The final decision is not to establish standards for momentary interruptions.[47] Technologies such as reclosers and feeder automation allow some long outages to be resolved quickly – essentially turning them into momentary interruptions. The reliability standards framework seeks to encourage this, by not establishing targets to limit the number of momentary interruptions.

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[43] The Distribution Reliability Measures Guideline prescribes a set of common definitions and measures to assess and compare the reliability performance of distributors. (See Australian Energy Regulator, *Distribution Reliability Measures Guideline*, November 2018, available at https://www.aer.gov.au/system/files/D18-164601%20AER%20-%20Distribution%20Reliability%20Measures%20Guideline%20-%20%20final%20for%20publication%20-%20clean%20-%2014%20Nov%202018.pdf).

[44] Alternative 'input' standards relate to the inputs to network planning required to deliver reliability performance. Examples include prescribing the availability of bulk supply (as with the national electricity market bulk supply standard of prescribing maximum unserved energy), or defining categories to drive particular levels of redundancy in the network (as in the Commission's Electricity Transmission Code).

[45] Essential Services Commission of South Australia, 2*005 – 2010 Electricity Distribution Price Determination Part A: Statement of Reasons*, April 2005.

[46] For example, if one customer had an outage of 60 minutes CAIDI would be 60 minutes. Likewise, if 100,000 customers had an outage of 60 minutes, CAIDI would be 60 minutes.

[47] Momentary interruptions are currently defined as interruptions lasting less than one minute. This final decision will change that definition to be interruptions lasting less than three minutes (see section 3.6 of this final decision).

3.3 Measures will apply to feeder categories

The final decision is to continue to set network reliability standards for four feeder-type categories (CBD, Urban, Short Rural and Long Rural).

Feeder category definitions will be updated to align with those in the AER's revised STPIS, which was released in November 2018.[48] The definitions are set out in Table 3.

The final decision to set network reliability standards for each feeder category reverses the draft decision of setting standards for each of ten regional categories.

This section sets out background information on why the network must be segmented to set reliability standards and revisits reasons for the draft decision, before presenting the rationale for this final decision.

Table 3: Definitions of feeder-type categories, current (2015 – 2020) and revised (to apply from 2020 – 2025)

Feeder-type category	Definition
CBD feeder	Current: A feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas. Revised: A feeder in the CBD area supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.[49]
Urban feeder	Current: A feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 mega-volt amps/km. Revised: A feeder, which is not a CBD feeder, which has a three-year average maximum demand over the three-year average feeder route length greater than 0.3 mega-volt amps/km.
Short rural feeder	Current: A feeder, which is not a CBD or urban feeder, with a total feeder route length less than 200 km. Short Rural feeders may include feeders in urban areas with low load densities. Revised: A feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km.
Long rural feeder	Current: A feeder, which is not a CBD or urban feeder, with a total feeder route length greater than 200 km. Revised: A feeder which is not a CBD, urban feeder or short rural feeder.

48 Australian Energy Regulator, *Service Target Performance Incentive Scheme*, p. 28.

49 Note that the definition of a CBD feeder in the revised Service Target Performance Incentive Scheme allows for equivalent areas outside the CBD to be included in this category, as follows: 'A feeder in the CBD area of a State or Territory capital; and other equivalent areas that are applicable in the relevant participating jurisdiction as supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.'

3.3.1 Background: why segment the network?

SA Power Networks' distribution system comprises some 1,720 feeders. Across those feeders, reliability varies depending on the physical structure of the network, its surrounding environment and the number of redundant elements it contains. [50] As reliability varies, it is not desirable to set standards for the whole network. However, it is not feasible to set and monitor standards for each individual feeder. Two generally utilised network segmentation methodologies are: geographic regions, which represent differences in reliability performance; and, feeder categories based on feeder line length, customer load and level of redundancy.

The Commission has discretion in determining how to segment the distribution network for the purpose of setting reliability standards. The Electricity Act requires the Commission to set standards to maintain reliability. It does not specify whether reliability should be maintained for individual customers, whether average reliability should be maintained for each region or feeder category, or whether average reliability should be maintained for the whole distribution network.

Prior to 2015, network reliability standards applied to seven regions, which still form the basis for reporting by the Commission. Feeder categories have been the basis for network reliability standards since 2015, when the Commission replaced the previous regional categories.

The core principle in choosing how to segment a network is to group customers together for whom the cost of supply is similar, and who value reliability in a similar way. This groups together those customers for whom the benefits and costs of reliability improvement are similar, ensuring that the reliability standards are targeted and incentivise SA Power Networks to deliver reliability outcomes that deliver net benefits to customers. This principle is consistent with promoting economic efficiency and with the Commission's primary objective of protecting the long-term interests of South Australian consumers with respect to the price, quality and reliability of essential services.

Both feeder categories and regions achieve that core principle to some extent.

Grouping customers with similar values of reliability would need to be done by customer type (residential, small business, large commercial, industrial, etc). As those customers are generally dispersed under both feeder-type and regional classifications (other than in relation to the Adelaide CBD, which is separately classified under each method), both approaches are likely to account for similar customer values equally well.

Segmenting by feeder categories will, to a certain extent, classify feeders with similar costs of supply as it will take into account similar demands and customer densities on each feeder, which drive the costs of reliability. Segmenting by region will also, to a certain extent, group feeders with similar costs as localised weather conditions, topography and distance to respond to interruptions are geographical factors that drive costs. It is not possible to quantify the impacts of those different drivers on the cost of reliability and the Commission is therefore unable to determine if regional or feeder-type segmentation better achieves the core principle.

The Commission has also had regard to the following principles to inform its decision:

- promoting consistency over time
- promoting national consistency
- the extent to which each type of network segment facilitates technology change, and
- suitability for communicating with customers.

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[50] Redundant elements mean that if one element fails, supply is not interrupted because electricity can be delivered through another path.

3.3.2 Why did the Commission introduce feeder category standards and are those reasons still important?

The Commission introduced standards based on feeder categories in 2015 to align jurisdictional reliability standards with the STPIS targets, improve national consistency, and allow benchmarking against other jurisdictions.

The focus was on the first reason, aligning jurisdictional standards and the STPIS targets. The final decision for 2015 – 2020 noted this alignment would 'minimise the possibilities for conflicting financial drivers and incentives for SA Power Networks', which the Commission considered existed under the STPIS.[51] For this Review, these reasons have been re-examined, and are discussed below.

Do jurisdictional reliability standards and STPIS targets need to align?

Though it is important that jurisdictional reliability standards and STPIS targets do not conflict, they also do not need to align. They may have slightly different, complementary, objectives.

The purpose of jurisdictional reliability standards is to establish minimum levels of reliability. Revenue allowances must provide for delivering against those minimum standards, that is, to maintain services.[52]

The purpose of the STPIS is to incentivise distributors to maintain and improve reliability, when the drive for cost savings might otherwise cause reliability to decline. Targets are tightened each year to 'lock-in' past improvements.

Jurisdictional standards and the STPIS may each have different objectives. For example, each may focus on different aspects of reliability, or reliability outcomes at different scales.

Tasmania provides an example. There, jurisdictional reliability standards emphasise the importance of maintaining reliability in regions. Standards are set for 101 geographic areas, which are each classified into five supply reliability categories. The distributor, TasNetworks, is required by the jurisdiction to maintain reliability for each of the 101 geographic areas. Its STPIS targets apply to average performance of the five supply reliability categories.[53,54,55]

Elsewhere, jurisdictional reliability standards are set for feeder categories. Some jurisdictions simply use STPIS targets as a proxy for jurisdictional standards. However, other mainland jurisdictions all have more than one distributor, each with different STPIS targets. In practical effect this means other jurisdictions combine a regional approach and STPIS targets.

National consistency and benchmarking

National consistency means aligning with the AER Distribution Reliability Measurement Guideline. A final revised version was published on 14 November 2018.[56] SA Power Networks' reporting requirements will be minimised where the jurisdictional framework aligns with this Guideline. However, if the jurisdictional framework is set on a different basis, nationally consistent data will still be available for benchmarking, because the AER collects performance data for this purpose directly from SA Power Networks.

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51 Essential Services Commission of South Australia, *SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period Final Decision*, 2014.

52 National Electricity Rules, section 6.5.7(a).

53 Office of the Tasmanian Economic Regulator, Aurora Energy and Office of Energy Planning and Conservation, *Joint Working Group Final Report, Distribution Network Reliability Standards, Volume 1 – Summary of Recommendations and Overview*, 2007, available at https://www.economicregulator.tas.gov.au/Documents/Distribution%20Reliability%20Final%20Report%20V1%20February%202007.pdf.

54 Office of the Tasmanian Economic Regulator, *Tasmanian Electricity Code*, 2017, section 8.6.11, available at https://www.economicregulator.tas.gov.au/Documents/Chapter%208%20revised%20TEC%205%20April%202017.PDF.

55 Australian Energy Regulator, *TasNetworks Determination 2017-19, Final Decision Overview*, 2017, pp. 40-42, available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2017-2019.

56 Australian Energy Regulator, *Distribution Reliability Measures Guideline*, November 2018.

3.3.3 Draft decision: reliability standards for ten regions

Before proposing regional standards in the draft decision, a critical question was 'will serving two different, but complementary, sets of reliability objectives cost more?'

Expenditure needed to maintain reliability will be minimised if jurisdictional reliability standards and STPIS targets are set on the same basis. (For example, if they each apply to mean feeder category USAIDI and USAIFI performance). However, in the current environment of stable electricity consumption and demand in South Australia, marginal expenditure on network reliability is low, as explained in section 3.1.2. In that context, the draft decision set out three main reasons for proposing regional reliability standards.

First, to improve communication, accountability and transparency. In SA Power Networks' customer engagement and the Commission's direct engagement with stakeholders, there was concern about the ongoing difference in service levels between metropolitan and regional customers. There was an increased focus on reliability in regions since the Commission's last review.

Second, to prevent reliability decline in regions. The Commission noted that both jurisdictional reliability standards, and STPIS targets, are focused on mean feeder category performance. The lowest-cost way to improve mean performance is to invest in areas with high customer density. In these areas, the cost of improvements for each customer is low (given the associated economies of scale and scope available).

It reasonable to expect that, over time, reliability improvements in higher density areas might offset decline in lower density areas. Though no such systemic decline has been observed since switching to feeder categories in 2015, it would only be evidenced in the medium to long-term. The draft decision to set standards for regions sought to prevent this before it occurs.

This reason echoed the finding of the Commission's 2017 Eyre Peninsula Inquiry, that feeder category standards did not provide strong and clear incentives for SA Power Networks to maintain regional performance.[57]

Third, the draft decision noted the Australian Energy Market Commission's (AEMC) decision on the principle of allowing off-grid supply as an alternative to grid-supplied network services. [58] If off-grid supply becomes a regulated distribution service and is provided by SA Power Networks, its reliability performance would have to comply with jurisdictional standards. Off-grid supply would be difficult to relate to the current feeder-type category targets; however, it would relate simply to regional standards.

Other supporting reasons for the draft decision were that: regional standards provide the basis for targeted improvements in specific areas, if required; and that they align with SA Power Networks' network planning practices.

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[57] Essential Services Commission of South Australia, Inquiry into reliability and quality of electricity supply on the Eyre Peninsula Final Report October 2017, available at https://www.escosa.sa.gov.au/projects-and-publications/projects/inquiries/inquiry-into-reliability-and-quality-of-electricity-supply-on-the-eyre-peninsula.

[58] Australian Energy Market Commission, *National Electricity Amendment (Alternatives to grid-supplied network services) Rule*, 2017.

3.3.4 Submissions to draft decision

Five of the six submissions to the draft decision specifically address the matter of introducing regional reliability standards. Submissions from Business SA, the Energy Security for South Australia Working Party and SACOSS support the change on the basis that it would improve communication, accountability and transparency:

- Business SA explains that: '[a]s per our long-standing position on this matter, we support reliability standards being determined on a regional basis to better align with broader accountability structures in the state, and to reflect the nature of more localised reliability issues which have come to bear in recent years. There are no electorates for short or long rural feeders, and while this is a simplistic view to make the point, there needs to be a stronger degree of transparency around specifically where reliability issues actually occur.'[59]
- SACOSS 'supports [the Commission's] draft decision to set region-based standards, which we agree will provide a more complete picture of increases or decreases in current reliability levels, and may better incentivise SA Power Networks to consider options to improve the reliability of worst served customers.'[60]
- The Energy Security for South Australia Working Party supports 'revert[ing] back to a region-based reliability standard to ensure that Eyre Peninsula receives power supply reliability equal to that received in other rural areas of South Australia'.

The Commission acknowledges that stakeholders are concerned with regional performance and SA Power Networks' accountability for its performance in regions. It considers that an enhanced reporting and monitoring regime can address these concerns. This is discussed further in section 6.1.

The submission from the Clean Energy Council is supportive of the change on the basis that it would accommodate performance of off-grid supply if it becomes a regulated distribution service. The Clean Energy Council submits that this approach will ensure off-grid supply can be offered at a price and with protections similar to off-grid supply.

As acknowledged in the draft decision, the Commission considers that accommodating off-grid supply in jurisdictional reliability standards is important. However, the AEMC has yet to make the rule changes required to allow off-grid supply as an alternative to grid-supplied network services. [61] The AEMC has an ongoing work program to develop these rule and law changes, and the Commission will await its decisions before making any required changes.

The submission from SA Power Networks does not support establishing regional reliability standards. It instead 'advocates for a retention of the existing regime where by reliability standards are established by the national feeder category definitions with reporting on reliability performance at the proposed regional level'.

SA Power Networks sets out three reasons for this position. While the Commission's final decision on this matter aligns with SA Power Networks' position, the rationale for each is different. SA Power Networks' reasons are:

- That regional performance data cannot be effectively 'normalised' to minimise annual variations in to what SA Power Networks considers 'acceptable levels'.

  The Commission's response is that SA Power Networks correctly identifies that annual performance of regions is highly variable, and that it continues to be variable after it has been normalised to remove the impact of significant performance events (for example, storms).

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[59] Business SA submission to the Review draft decision.
[60] South Australian Council of Social Services submission to the Review draft decision.
[61] Australian Energy Market Commission, *National Electricity Amendment (Alternatives to grid-supplied network services) Rule*, 2017.

However, customers want this variation to be transparent and clearly communicated. Further, it need not be a barrier to setting regional reliability standards. Standards can be designed so they are met if performance misses a target, but is inside an acceptable range.

- That regional standards would not align with the national regime (ie the AER's STPIS) and other mainland jurisdictions.

  The Commission's response is that though national consistency is important, jurisdictional reliability standards may usefully have slightly different objectives. If so, it may be desirable not to align completely with the national regime.

- That the definition of low reliability feeders would change as a result, with low reliability feeders defined relative to regions rather than feeder-type performance targets.

  The Commission's response is that SA Power Networks correctly identifies that the changed definition of low reliability feeders would capture fewer feeders on the Eyre Peninsula and in the Eastern Hills. Instead, the feeders with the lowest reliability in each region would be highlighted. This is the Commission's intention.

  Reporting on this basis highlights how performance of individual feeders in each region varies around the mean. Reporting of low reliability feeders on this basis will be included in the enhanced reporting regime (see section 6.3). This will complement SA Power Networks' new reporting to the AER of low reliability customers, which will be on a network-wide basis.[62]

The Commission does not consider that the reasons presented by SA Power Networks justify retaining feeder categories. The Commission's rationale relies on different reasons, as set out in the next section.

3.3.5 Final decision: rationale

The reasons for proposing regional standards set out in the draft decision, and the reasons stakeholders supported that proposal, can be addressed within the existing feeder category framework. There are five reasons why.

First, improved communication, accountability and transparency can be equally achieved through an enhanced reporting and monitoring regime which would include:

- Increased public reporting: for ten regions, rather than the current seven. Each year, SA Power Networks will be required to explain each region's performance by drawing a comparison with long-term performance, describing incidents or events that have affected performance, and its immediate and strategic responses.
- Increased monitoring and analysis: the Commission will monitor trends in average regional performance, and of performance of individual feeders in each region. The Commission will publish a summary of issues that emerge.

Second, though the Commission is concerned about the potential for reliability to decline in regions, there is no available evidence that suggests that a decline is happening at the present or is likely to happen in the short to medium term.

In its submission to the draft decision, SA Power Networks notes it is 'too early to conclude that the current feeder category reliability service standards could lead to a decline in regionally based reliability performance as suggested by [the Commission].' [63]

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62 The definition of low reliability customers is those with greater than four times network average USAIDI, calculated as a three-year rolling average.

63 SA Power Networks submission to the Review draft decision.

It notes that, over the last five years and over the last ten years, regional reliability performance has improved or been steady in eight regions, and declined slightly in two; the Eastern Hills and the South East. It submits that this decline 'is a result of the increased severity of the [significant weather events] since July 2010 not due to SA Power Networks' performance'.[64]

The Commission examined reliability in ten regions using a method for normalising regional performance that accounts for some local severe weather events (see section 6.2). It found that, since 2005-06, regional reliability (USAIDI) has been steady or improved slightly, with one exception; the Eastern Hills. In the Eastern Hills, normalised USAIDI increased (worsened) by an average of six minutes each year from 2005-06 through to 2017-18.[65] (This analysis is of performance before adjusting for major regional centres, see section 6.1).

In the absence of evidence that decline is occurring now, an enhanced reporting and monitoring regime is a proportionate response.

The Commission expects SA Power Networks to maintain regional reliability, using its existing resources. SA Power Networks' current practice of targeting its expenditure at maintaining historical reliability levels for individual customers (where practical) should assist in this regard. The Commission retains the discretion to require targeted improvements in specific areas, as it did for Kangaroo Island in the 2010 – 2015 period, if regional decline becomes evident.

Third, the Commission is responding to the views from its stakeholder engagement that all options for controlling the costs of electricity distribution services need to be considered. Further, evidence from the Review's customer survey is that there is limited willingness to pay to improve reliability.

Changes to the basis of reliability standards have the potential to affect SA Power Networks' costs over time. In smaller, regional categories, there is less potential for lower cost improvements in high-density areas to offset higher cost maintenance or improvements in low-density areas. Cost changes would not be immediate, but would arise in incremental decisions about repair and replacement expenditure.

This was noted in the draft decision, and submissions did not oppose regional standards on that basis. For example, SACOSS acknowledges that regional standards may change the costs of maintaining reliability over time, and notes the potential for changes in technology to lower costs.[66]

These cost impacts are likely to be minimal in the 2020 – 2025 period, given the current environment of electricity consumption and demand in South Australia (see section 3.1.2). In the 2020 – 2025 period, SA Power Networks is likely to be able to continue to maintain regional reliability within a similar revenue range. This is supported by the fact that, in response to the draft decision to introduce regional standards, SA Power Networks did not propose additional expenditure for any specific region.

Despite these indications about the quantum of possible cost impacts, the Commission considers that the proportionate response to maintain regional reliability in the 2020 – 2025 period is to implement an enhanced reporting and monitoring regime. This will allow the Commission to continue to monitor performance trends and identify any areas that may require targeted improvements.

Fourth, the Commission is encouraged by recent revisions to the STPIS, the final version of which was released on 14 November 2018. In the revised STPIS, which will apply to SA Power Networks in the 2020 – 2025 period, the incentive rates for improving USAIDI and USAIFI will change. There will be greater incentive to improve USAIDI.

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64 SA Power Networks submission to the Review draft decision.

65 Data is more reliable from 2007-08 onwards. From then until 2017-18, performance worsened by four minutes each year. Starting from 2007-08 and excluding the impact of 2016-17 (a year severe weather impacted performance), performance improved by one minute each year.

66 South Australian Council of Social Services submission to the Review draft decision.

This will positively impact on customers in regions. With the current design, distributors have invested in avoiding interruptions (largely through capital expenditure), over reducing interruption length (which requires crews and operating expenditure).

The AER explains that 'customers at the further end of feeders are most likely to have long interruptions (because of the length of time it takes for maintenance crews to serve them)'.[67] They will benefit by distributors having more incentive to improve USAIDI. The Commission will monitor the impact of these revisions.

Fifth, the AEMC has yet to make the rule changes required to allow off-grid supply as an alternative to grid-supplied network services. [68] Currently, the National Electricity Rules do not allow SA Power Networks to provide off-grid supply through microgrids or individual power systems, as they are not regulated distribution services.[69] The role of jurisdictional standards in accommodating this change is unclear.

A number of submissions to this Review's December 2017 Objectives and Process paper asked the Commission to establish a reliability target for microgrids and address SA Power Networks' role in facilitating distributed energy resources.[70]

The Clean Energy Council's submission on the Commission's draft decision welcomed the move to set reliability standards for regions rather than feeder-type categories, on the grounds that this would accommodate the performance of off-grid supply if it becomes a regulated distribution service under the national regulatory regime. It also encouraged the Commission to discuss with the AEMC to ensure consistency.

The Commission considers that accommodating off-grid supply is important but will await the AEMC's decisions on rule and law changes before adjusting jurisdictional standards, if required. The Commission will continue discussions with the AEMC through its decision-making process.

3.4 Performance during significant events: included or excluded?

The final decision is to set targets for underlying performance, and separately consider performance during significant events.

The final decision is to separate underlying performance and performance during significant events so they may be examined separately. This is consistent with the draft decision, and continues the approach first introduced in 2015.

Underlying performance will be defined as normalised performance. Normalised performance will continue to be performance after MEDs are excluded, using the 2.5 Beta Method developed by the Institute of Electrical and Electronics Engineers (**IEEE method**).[71] MEDs are days when USAIDI is more than 2.5 standard deviations from the mean.

SA Power Networks will be required to report separately on its performance during days excluded under the MED methodology, with a particular focus on efficient restoration practices during MEDs.

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[67] Australian Energy Regulator, *Amendment to the Service Target Performance Incentive Scheme and Establishing a New Distribution Reliability Measurement Guideline Explanatory Statement*, 2018, available at https://www.aer.gov.au/system/files/Explanatory%20Statement%20-%20Amending%20the%20Service%20Target%20Performance%20Incentive%20Scheme%20%28STPIS%29%20and%20establishing%20a%20Distribution%20Reliability%20Measures%20Guideline%20%28DRMG%29.pdf.

[68] Australian Energy Market Commission, *National Electricity Amendment (Alternatives to grid-supplied network services) Rule*, 2017.

[69] The Australian Energy Market Commission found off-grid supply unlikely to constitute a distribution (or transmission) service, so it to be unlikely that a distributor would be permitted to provide it, though an affiliate or subsidiary of the distributor could do so.

[70] AGL, Clean Energy Council, and S&C Electric submissions to the Review Objectives and Process paper.

[71] Institute of Electrical and Electronics Engineers standard 1366-2012.

3.4.1 Submissions to draft decision

Two submissions directly addressed this decision point. The SA Power Networks submission and the Energy Security for South Australia Working Party submission each support separate assessment of underlying performance and performance during significant events.

The SA Power Networks submission raises concerns about how to identify underlying performance if reliability standards were to be established on a regional basis. These are addressed in section 6.2, which addresses how performance data will be normalised for the purpose of the enhanced reporting regime.

3.4.2 Rationale

Using different approaches to regulate underlying performance and performance in significant events recognises that some events are beyond SA Power Networks' control but still requires it to plan for risk and uncertainty.

Of the 31 MEDs in South Australia since 2010, all have been the result of significant weather. As the Commission noted in its decision for the 2015 – 2020 period:

> 'The impact of weather has consistently been a major contributor to SA Power Networks reliability performance. While SA Power Networks' distribution network must be built to perform consistently within normal weather conditions, distribution networks are not designed to withstand severe weather such as floods, bushfires or strong winds. As it would be very difficult (and, in any event, prohibitively expensive), to design an electricity distribution network to withstand all severe weather events, reliability measurements and improvement efforts should focus on performance during the normal course of events and efficient restoration practices when the network is under unusual stress.'[72]

It is important to be able to separate the impact of unusual weather conditions from mild weather on underlying reliability performance. This approach is consistent with the way performance data is normalised for the STPIS.

[72] Essential Services Commission of South Australia, *SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period Final Decision*.

3.5 Standard of endeavour

The final decision is that:

1. SA Power Networks' performance targets (for network performance and customer service) will continue to be of a 'best endeavours' nature.
2. Reporting on how SA Power Networks has applied its 'best endeavours' will only be required beyond a reporting threshold.
3. SA Power Networks must publish an annual Monitoring, Evaluation and Compliance Strategy (**MECS**) that outlines its strategy for applying its best endeavours.
4. SA Power Networks must publicly report on how it has applied its best endeavours where it misses performance targets, and following significant performance events.
5. To support the revised reporting accountability, the Commission will continue to conduct periodic assessments of the systems, processes and controls used by SA Power Networks to prepare and provide those reports, including the underlying data quality.
6. The Commission will also continue to issue long-term industry performance trends and statistics, and will also provide analysis of key events or compliance matters as necessary.

The final decision is that SA Power Networks' performance targets will continue to be of a 'best endeavours' nature. If a performance target is not met, but SA Power Networks has used its 'best endeavours' to achieve the target, the reliability standard is satisfied.

What does 'best endeavours' mean?

Best endeavours means to act in good faith and use all reasonable efforts, skills and resources. A best endeavours obligation is not as onerous as an absolute obligation (like 'must' or 'shall'). It requires that SA Power Networks does what is prudent and reasonable in the circumstances.

Though best endeavours does not require effort that goes beyond the bounds of reason, it is considerably more than casual and intermittent activities. It means acting honestly, reasonably and making a positive effort to perform the relevant obligation.

Best endeavours explanations will be needed beyond a 'reporting threshold'

SA Power Networks will only be required to report on how it has applied its best endeavours when its performance exceeds a reporting threshold. Currently, best endeavours assessments are conducted by the Commission each time a performance target is not met.

The reporting threshold will be set as the 75th percentile of year-to-year variation around the performance target (set as the historical average mean).[73] With a threshold set this point, 25 percent of annual performance values will be beyond the reporting threshold. A threshold based on a percentile value has been selected because it can be applied for each feeder category, and accommodate their different means and standard deviations.

The reporting threshold and performance targets will be calculated using a consistent time period. That is, if performance targets are established using five years' data, so too will reporting thresholds be established using five years' data.

73 That is, the performance target = ((Mean Y1 + Mean Y2 … + Mean YX)/X), and the reporting threshold = ((75th percentile Y1 + 75th percentile Y2 … 75th percentile YX)/X), where X is the number of years performance used for setting targets.

The Commission will retain the discretion to require best endeavours reporting or explanations in other instances, such as when there are two consecutive years when performance is worse than the target, but inside the reporting threshold. The concept and application of the reporting threshold are illustrated in Box 3.

Monitoring, Evaluation and Compliance Strategy (MECS)

SA Power Networks will be responsible for demonstrating how it has exercised its best endeavours to meet its service standards following significant performance events, or when performance is beyond the reporting threshold.

It will be required to do so with regard to a forward-looking Monitoring, Evaluation and Compliance Strategy (**MECS**). The purpose of the MECS is to outline how SA Power Networks will apply its best endeavours. The Commission will consult on the scope, content and form of the MECS as part of its Monitoring and Evaluation review, due for completion in 2019.

SA Power Networks will be responsible for deciding what level of explanation is required to prove it has applied its best endeavours. Explanations may include descriptions of technical actions, consideration of costs of improvements, and evidence on whether or not these are acceptable to customers. The Commission will use SA Power Networks' report to decide whether or not SA Power Networks has applied its best endeavours and so achieved the broader reliability standard.

Communicating with customers about performance

SA Power Networks must communicate proactively with its customers about its performance, and to explain, at a high level, variation in annual performance. The Commission currently uses information provided by SA Power Networks to produce public reports on its behalf (see section 5).

New requirements will include production of regional reports (see section 6.1), which describe performance, all variation from long-term performance, major outages (including causes) and network improvements.

Further, the Commission expects that SA Power Networks will continue to respond to its customers' expectations of receiving timely information about network performance.

Continued oversight of performance trends

As noted above, to support proposed changes, in the new regulatory period the Commission will continue to conduct periodic assessments of the systems, processes and controls used by SA Power Networks to prepare and provide reports for customers, including the underlying data quality.

The Commission will also continue to collect data on and analyse SA Power Networks' performance. It will monitor, query and report on longer-term performance trends, issue long-term industry performance trends and statistics and provide analysis of key events or compliance matters as necessary.

Box 3: Concept and application of reporting thresholds

In this example, hypothetical reporting thresholds are set for the 2015 – 2020 period. Five years' performance data is used, from 2009-10 to 2013-14. The 75th percentiles of annual performance across that five years is calculated, for each feeder category. These become the reporting thresholds, shown in Table 4.

That same five years' data was used to calculate the performance targets for the 2015 – 2020 period, which are the rounded means of historical annual performance. These performance targets are shown in Table 4.

Table 4: Performance targets and hypothetical reporting thresholds, 2015 – 2020

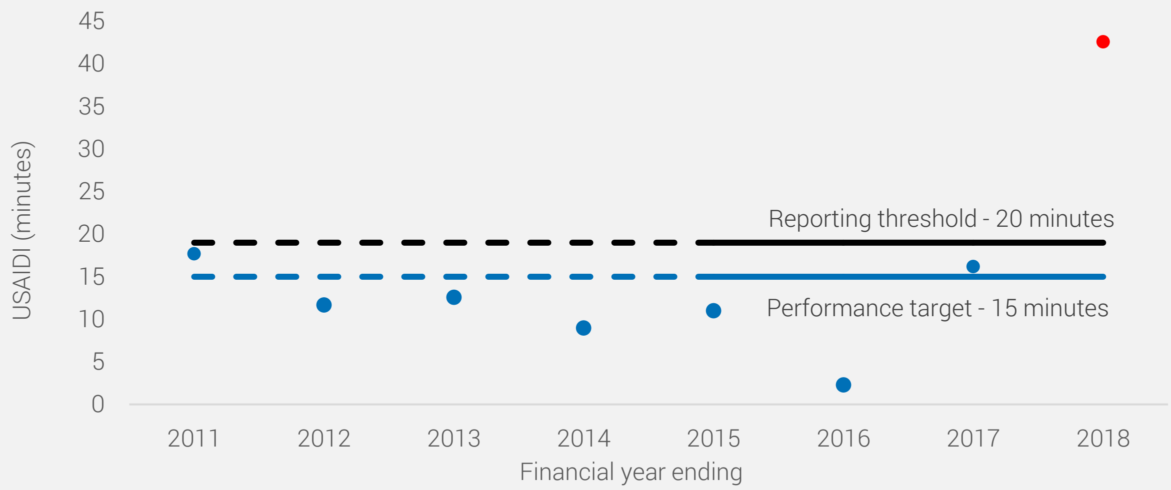
Feeder category	Targets USAIDI, mean of performance 2009-10 to 2013-14. Mean before rounding shown in brackets.	Reporting threshold USAIDI, 75th percentile of performance 2009-10 to 2013-14 75th percentile before rounding shown in brackets.	Difference (USAIDI)	Difference (%)
CBD	15 (12)	20 (15)	3	26%
Urban	120 (116)	130 (128)	11	10%
Rural short	220 (222)	250 (248)	27	12%
Rural long	300 (300)	340 (341)	41	14%

Note: differences calculated before rounding.

Performance in 2015-16, 2016-17 and 2017-18 has been assessed against these targets. In this example, full best endeavours explanations would only be required when the reporting threshold is exceeded.

For CBD feeders, the historical average mean of 12 minutes was rounded up by 25 percent to 15 minutes, making the performance target the same as the reporting threshold. To account for that, in this example, the reporting threshold has been set at 125 percent of the target, ie as 19 minutes (rounded to 20 minutes). The concept is illustrated in Figure 4, again for CBD feeders.

Figure 4: CBD feeder performance, shown against the performance target and reporting threshold for 2015 – 2020



In Figure 4, the 'performance target' is shown as a solid blue line. It is the rounded mean of performance over 2009-10 to 2013-14 (shown as a dotted blue line). The reporting threshold is shown as a solid black line. It is the 75th percentile of performance over 2009-10 to 2013-14 (shown as a dotted black line). Note that CBD feeder performance of 2016-17 of 16 minutes is inside the reporting threshold.

3.5.1 Submissions to draft decision

The draft decision was the same as this final decision, but did not limit 'best endeavours' explanations to instances where performance is beyond a reporting threshold (item (2) in the above decision box).

Two submissions to the draft decision addressed the proposal that SA Power Networks' reliability standards will continue to be of a best endeavours nature. Both the SACOSS and SA Power Networks submissions support continuation of best endeavours reliability standards. SACOSS 'cautiously support' the requirement for SA Power Networks to publish a MECS, on the basis it does not increase costs to customers.

3.5.2 Rationale

Continuation of the best endeavours standard reflects that factors outside of SA Power Networks' control can influence network performance. The best endeavours approach allows the Commission discretion in deciding if SA Power Networks' performance is acceptable, and in selecting enforcement measures.

Continuation of this approach is supported by stakeholders. Placing responsibility for making best endeavours explanations with SA Power Networks will enhance its accountability for outturn performance.

The Commission has reflected on obliging SA Power Networks to make a best endeavours explanation each time performance targets are exceeded. The nature of the Commission's performance targets means there are instances where performance in each individual year will vary from the target, without there being an issue in underlying performance. This is because performance targets are set as historical mean performance. Some variation can be reasonably expected, while still being consistent with historical performance.

The draft decision noted that the Commission had explored 'defining a tolerance band around each target, within which best endeavours would be automatically be met'.[74] The draft decision settled against this approach because the Commission considered that even in the case of reasonably expected variation, performance patterns and reasons for variation should still be clearly set out.

The Commission still considers it important that variation is transparent and explained to customers, but does not wish to make disproportionate requirements of SA Power Networks. Setting a reporting threshold is a way to balance these interests.

Judgment is required in setting the reporting threshold. The Commission considers this a necessary task to balance the needs and expectations of customers with making fair reporting obligations of SA Power Networks.

Currently, if performance targets are missed, the Commission considers the magnitude by which the target was missed, in assessing whether SA Power Networks has applied its best endeavours. (The current process is set out fully in Box 4). This affects the extent and detail of the best endeavours investigation. However, how much it matters is essentially a qualitative assessment.

In the Commission's judgment, setting the threshold at the 75th percentile of year-to-year variation for each region is reasonable. Set at this point, over time, performance will be beyond the reporting threshold every four years.

Ongoing oversight by the Commission will allow the relevance of this threshold to be tracked. It will not preclude detailed investigations and further explanation from SA Power Networks where the Commission considers it to be necessary. The threshold will be reviewed as required.

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[74] Essential Services Commission of South Australia, *SA Power Networks Reliability Standards Review Draft Decision*, August 2018, p. 29, available at https://www.escosa.sa.gov.au/ArticleDocuments/1186/20180802-Electricity-SAPowerNetworksReliabilityStandardsReviewSSF20-DraftDecision.pdf.aspx?Embed=Y.

Though the circumstances for a detailed best endeavours explanation will be limited, variation in performance and the high level reasons for that will be visible in SA Power Networks regular reporting.

Box 4: Current requirements for demonstrating best endeavours

This description of current requirements for demonstrating best endeavours was included in the draft decision.

The Commission monitors and reports on its assessment of how SA Power Networks exercises its best endeavours in each year of the regulatory period. Currently, in reporting to the Commission, SA Power Networks must set out if performance targets have been met and, if not, why not. Explanations are expected to provide sufficient information to enable the Commission to form a view as to whether or not best endeavours were employed.

Explanations might include, for example, what action was taken to avoid targets being missed, when that action was taken, preparations prior to events (such as internal procedures and protocols set for handling such instances, the level of planning and the ability to call on additional resources when required), and any subsequent improvements implemented.

The Commission then applies a best endeavours assessment. This is an assessment of SA Power Networks' explanation. In this assessment, the Commission takes into account:

- reasons for failing to meet the target
- the magnitude by which the target was missed (noting that an assessment is still performed, even if the target is narrowly missed)
- if the circumstances were reasonably foreseeable or beyond SA Power Networks' control
- remedial action undertaken in response to the missed target
- improvements in performance throughout the year
- long-term trends in performance
- the extent to which SA Power Networks has engaged with Commission staff, and
- the quality of information provided.

The Commission approaches enforcement in line with its Enforcement Policy 2013.[75]

3.6 Other exclusions: revised to be consistent with STPIS reporting

The final decision is to revise other exclusions from performance to be consistent with exclusions in the STPIS.

The Code currently defines an interruption as 'a planned or unplanned interruption of, or restriction to, distribution services of at least one minute in duration, other than an interruption or restriction due to an emergency, a generation failure or a transmission failure'. This is in addition to exclusion of performance on MEDs.

75 Essential Services Commission of South Australia, *Enforcement Policy Version 2.5*, 2013, available at https://www.escosa.sa.gov.au/ArticleDocuments/580/130905-EnforcementPolicy_V2-5.pdf.aspx?Embed=Y.

3.6.1 Submissions to draft decision

The SA Power Networks' submission states that reporting costs are minimised when the 'basis for recording an interruption' is the same for both the Commission and the AER's reporting regimes. It specifically mentions the definition of a customer and the definition of momentary interruptions.

The Commission agrees with the merits of aligning the Code's definition of an interruption with the exclusions in the STPIS and notes their similarity. However, aligning the definition of a customer is more complex.

In the Code, 'customer' has the meaning given to the term in the Electricity Act, 'namely a person who has a supply of electricity available from a transmission network or distribution network for consumption by that person'. The STPIS uses a definition of 'customer base', which refers to the number of 'distribution customers' at the start and end of a period, with 'distribution customers' defined as per the National Electricity Rules.

The Commission will further consider the merits of aligning the definition of a customer, so this may be an input into the next Electricity Act review.

3.6.2 Rationale

This change will improve regulatory consistency. The exclusions in the STPIS (set out in Appendix 4) are broadly consistent with the Code's current definition of an interruption, with the exception of the change in definition of momentary interruption from one minute to three minutes.

With regard to the three-minute momentary interruption definition, the AER's rationale regarding the shift from one-minute is that it will 'encourage investment in automation facilities to restore supply more quickly after a network fault'.[76] This change arises from a recommendation from the 2014 AEMC Review of Distribution Reliability Measures.[77]

While a one-minute definition promotes use of established technologies like reclosers, the three-minute definition promotes newer technology, such as feeder automation, that takes more than one minute but less than three to restore supply. Both definitions promote momentary interruptions instead of longer interruptions, but extending the definition to three minutes allows use of a wider range of technologies.

The Commission acknowledges the concern that S&C Electric expressed in its submission to the Review's Objectives and Process paper: that momentary interruptions are inconvenient to customers, particularly business customers, and pose a challenge to the use of distributed energy resources.[78]

However, widening the definition will not promote momentary interruptions but instead promote potentially long interruptions being 'turned into' momentary interruptions, because it will encourage a wider range of feeder automation technology. The frequency of interruptions will remain the same, but duration of interruptions will fall, reducing overall inconvenience to customers.

[76] Australian Energy Regulator, *Amendment to the Service Target Performance Incentive Scheme and Establishing a New Distribution Reliability Measurement Guideline Explanatory Statement*.

[77] Australian Energy Market Commission, *Review of Distribution Reliability Measures*, 2014, available at https://www.aemc.gov.au/markets-reviews-advice/distribution-reliability-measures.

[78] S&C Electric submission to the Review Objectives and Process paper.

3.7 Restoration targets introduced

The final decision is to introduce restoration time targets for each feeder category. Targets will relate to outages longer than two hours, and outages longer than three hours.

Restoration targets will vary for each feeder category, and will be established to maintain current performance. As with the other network reliability measures, targets will relate to underlying performance, and performance on MEDs will be considered separately.

The draft decision was to set restoration targets for customers who have outages. It proposed to set a target for the proportion of customers that must be restored within two hours, and that must be restored within three hours, in each region. These were to apply on average, across each year.

The final decision is to set restoration targets that apply across all customers. Targets will be set for how much of the customer base experiences long outages. A target will be set for the maximum proportion of the customer base that may experience an outage longer than two hours, and longer than three hours, in each feeder category. These will apply on average, across each year.

3.7.1 Submissions to draft decision

Two submissions to the draft decision address the proposal to reinstate restoration targets.

The SA Power Networks' submission accepts inclusion of restoration of supply targets but expresses concern that targets relate only to customers who have experienced an outage. In its view, this means that 'the measure being contemplated can indicate a decline, when there has been an improvement'. SA Power Networks illustrate this concern with an example.

In SA Power Networks' example (summarised in Table 5) a fault occurs near the end of a distribution line and 1000 customers lose power. There is a manual switch halfway between the fault and the nearest recloser. When crews inspect the line, they use the manual switch to restore half of the customers within 60 minutes. Restoring supply to the other customers takes longer, 180 minutes. The average restoration time is 120 minutes.

Table 5: Measurement of performance against restoration targets (comparison of final and draft decisions)

	Proportion of customers with supply interruption restored within two hours (draft decision)	Proportion of customer base with outage longer than two hours (final decision)	SAIDI	SAIFI	CAIDI
Example 1: In a group of 1000 customers, 500 have an outage of 60 minutes, and 500 have an outage of 180 minutes	50%	50%	120	1.0	120
Example 2: In a group of 1000 customers, 500 have an outage of 170 minutes	0%	50%	85	0.5	170

Note: examples are the same as those used in SA Power Networks' submission to the draft decision.

An improvement is made to replace the manual switch with another recloser. This means that an identical fault in the same location would affect only 500 customers. The other 500 customers would not lose power at all, and because crews can concentrate their efforts, the restoration time for the other 500 customers falls to 170 minutes. Despite this being a better overall result, the average restoration time, across those customers who lose power, is now 170 minutes.

The core network reliability measures, USAIDI and USAIFI, reflect the improvement in this example. USAIDI falls from 120 minutes to 85 minutes, and USAIFI from 1.0 to 0.5 interruptions.

SA Power Networks explains that this example illustrates its current approach to managing outages: to reduce the number of customers who experience outages by installing additional automatic reclosers in its network. Improvement in USAIFI since 2005-06 (USAIFI represents the customers interrupted as a percentage of the customer base), is 'mainly the result of eliminating shorter duration outages for some customers'. By reducing the number of customers that experience outages, SA Power Networks is able to focus its resources to reduce outage length for others.

SA Power Networks proposes that an alternative measure would better reflect customer outcomes. Specifically, 'the proportion of the customer base who experience an outage of more than x hours'.

The SACOSS submission 'cautiously supports the reintroduction of the restoration targets on the basis that those targets do not require additional emergency response or operational expenditure. The existing practices employed by SA Power Networks should be adequate to meet restoration targets imposed'. SACOSS notes the $214 million for emergency response expenditure in SA Power Networks' Draft Plan, and submits that this should not be linked to the Commission's restoration targets.

3.7.2 Rationale

The impact of implementing SA Power Networks' proposal is illustrated in Table 5. It uses the same examples as SA Power Networks' submission, and shows both the proportion of customers with supply interruption restored within two hours (the target proposed in the draft decision), and the proportion of the customer base with an outage longer than two hours (as set out in the final decision).

Setting restoration targets that apply to all customers will encourage both efforts to avoid outages occurring, and efforts to restore power once it has been interruption.

The Commission accepts the modification suggested by SA Power Networks. It does not undermine the intention of introducing restoration targets. Restoration targets in this form will:

- provide an alternative to the weak signal for timely restoration currently provided by duration payments (note that there is no proposal to link GSL payments, or other financial incentives, to restoration targets)
- be consistent with the Commission's decision not to adopt CAIDI as a core measure of network reliability as outlined in section 3.2, and
- be more meaningful to customers than the proposal in the draft decision, as they will put outages experienced by a small number of customers into context.

Targets will be established to maintain current performance, and so not require additional expenditure.

The final decision is to set restoration targets for feeder categories rather than regions, to be consistent with its requirements for network reliability standards.

4 Guaranteed service level (GSL) scheme

This section addresses the second of the reliability standard framework's four main elements: the GSL scheme. Under the GSL scheme, SA Power Networks must automatically make payments to customers in the event that specified service levels are not met.[79]

There are currently five types of GSL payments: duration of interruption payments (**duration payments**), frequency of interruption payments (**frequency payments**), promptness of new connection payments, timeliness of appointment payments, and timeliness of street light repair payments.

The GSL scheme acknowledges the inconvenience customers experience when SA Power Networks does not meet its service obligations. The network reliability payments (duration payments and frequency payments) serve to acknowledge that some of the worst served customers are unlikely to receive future service improvements due to the high costs of improving their supply.[80]

Importantly, GSL payments do not provide compensation for individual loss or damage that a customer may suffer, nor are they hardship payments. [81]

GSL payments will change from 1 July 2020

The final decision is that there will be changes to the GSL scheme from 1 July 2020. For interruptions to electricity supply, payments will be made when a customer experiences more than 20 hours of interruptions over one financial year. This will replace the current system of payments for one-off outages lasting more than 12 hours.

A further flat payment will be made when a customer experiences more than nine individual interruptions (each longer than three minutes) in a financial year. This will replace the current system of payments, which increase depending on whether a customer experiences more than nine, more than 12, or more than 15 interruptions.

GSL payments for timeliness of appointments will be removed, while GSL payments for promptness of new connections, and timeliness of street light repairs will remain unchanged. These changes are summarised in Table 6, and set out in detail in the following sections.

Table 6: Changes to the GSL scheme to apply from 1 July 2020

Current payment	Payment to apply from 1 July 2020	Amount (GST inc.)
Duration of interruption payments – five payment levels (>12 and ≤15 hours, \$100; >15 and ≤18 hours, \$150; >18 and ≤24 hour, \$200; >24 and ≤48 hours, \$405; >48 hours, \$605)	Total annual duration of interruption > 20 and ≤ 30 hrs	\$100
	Total annual duration of interruption > 30 and ≤ 60 hrs	\$150
	Total annual duration of interruption > 60 hrs	\$300
Frequency of interruption payments – three payment levels (>9 and ≤12 interruptions pa, \$100; >12 and ≤15 interruptions pa, \$150; > 5 interruptions pa, \$200)	Frequency of interruptions > 9 interruptions 3 minutes or longer pa	\$100

79 Electricity Distribution Code 12.1, section 2.3.

80 Essential Services Commission of South Australia, *2005 – 2010 Electricity Distribution Price Determination: Statement of Reasons*.

81 SA Power Networks has a separate compensation scheme that may apply customers who have incurred economic loss as a result of negligence by SA Power Networks.

Current payment	Payment to apply from 1 July 2020	Amount (GST inc.)
Promptness of new connections – within 6 business days	No change	$65 per day to a max. of $325
Timeliness of street light repairs – metropolitan areas – within 5 business days	No change	$25 per 5 business day period
Timeliness of street light repairs – country (all other areas) – within 10 business days	No change	$25 per 10 business day period
Timeliness of appointments - no more than 15 minutes late	Discontinued	-

4.1 Network reliability payments

The final decision is to continue network reliability payments, with the following changes:

- Duration of interruption payments (**duration payments**) for one-off outages will be removed.
- Total annual duration payments (**total duration payments**) will be introduced.
- Frequency of interruption payments (**frequency payments**) will be simplified.

Network reliability payments will continue

The Commission is of the view that a jurisdictional GSL scheme is beneficial, as it allows local conditions, and the preferences of South Australian customers, to be accounted for. The GSL scheme in the STPIS includes network reliability payments and would apply in the absence of a jurisdictional scheme.

The GSL scheme in the STPIS includes three network reliability payments: duration of interruption payments (for one-off outages); total duration of interruption payments (for more than 20 hours of outages in a financial year); and frequency of interruption payments (based on the number of outages in a financial year).[82]

The Commission has assessed customer's willingness to pay for network reliability payments (specifically duration payments, which account for 97 percent of scheme costs) using a customer survey. Results showed that in aggregate, customers are willing to pay $6.4 million per annum for duration payments (an average of $7 per year, per customer).

Duration payments will be removed

Duration payments, in their current form, will be removed from 1 July 2020. There are three reasons why.

First, they are poorly targeted to the customers identified in the scheme's objective: those unlikely to receive future service improvements due to the high costs of improving their supply. Some duration payments are made to customers experiencing ongoing and persistent reliability issues. For example, since 2010, 37 percent of duration payments (accounting for 24 percent of payment value) have been made to customers on low reliability feeders.

82 Australian Energy Regulator, *Service Target Performance Incentive Scheme*, section 6.3.

However, a large proportion of payments are made to customers who experience a one-off outage, but typically have average or good reliability. For example, since 2010, 53 percent of duration payments (accounting for 87 percent of payment value) related to outages on MEDs.

Second, current levels of duration payments are not a strong driver of SA Power Networks' response to interruptions. Incentivising timely response to interruptions has previously been referred to as a secondary objective of duration payments.[83] Following an unplanned interruption, SA Power Networks is obliged to use its best endeavours to restore supply to all customers as soon as possible.[84] It takes a structured approach to this, set out in Box 5.

Box 5: SA Power Networks' approach to restoring supply after an unplanned interruption

In restoring supply following an unplanned interruption, SA Power Networks prioritises safety, then restoring power to high voltage lines. It then restores power to customers in line with priorities agreed with the SA Government. [85] These priorities are restoring supply for:

1. State electricity grid
2. Communications
3. Water for drinking
4. Wastewater
5. Hospitals, aged care
6. Bulk transport
7. Major shopping centres
8. Emergency services control centres
9. Correctional services
10. Major industrial customers, then
11. Residential and small business customers.

In restoring supply for residential customers, SA Power Networks considers where it can restore the most customers in the shortest time, before turning its attention to those most likely to be off-supply for the longest period. The lowest duration payment threshold (12 hours) provides a weak restoration incentive in this context.

Third, removing duration payments for one-off outages will reduce the total cost of the GSL scheme, and so the costs recovered from customers. Results from the customer survey indicate that customers are willing to pay less for duration payments than now ($6.4 million pa rather than $10.1 million pa) and not all customers are willing to pay anything for duration payments (52 percent are willing to pay something, 42 are not willing to pay anything, and six percent do not know.) [86]

[83] Essential Services Commission of South Australia, *South Australian Electricity Distribution Service Standards 2010-2015 Final Decision,* 2008.

[84] National Energy Retail Rules, Part 4, 91 c.

[85] Essential Services Commission of South Australia, *Distribution Licence Compliance Review of SA Power Networks in Relation to the 27-28 December 2016 Severe Weather Event,* June 2017, pp. 16-17, available at https://www.escosa.sa.gov.au/ArticleDocuments/1054/20170623-Electricity-SevereWeatherEvent27-28Dec2016-DistributionLicenceComplianceReview-SAPN.pdf.aspx?Embed=Y.

[86] Error bands for these results, at a 95 percent confidence level, are 3.1 percent for residential responses and 5.6 percent for business responses.

Total annual duration payments will be introduced

Total annual duration payments will replace duration payments for one-off outages. They will apply at the end of each financial year, in relation to outages over the course of a year, including those on MEDs. Three levels of payment are proposed, as shown in Table 6.

Total duration payments will better target customers experiencing ongoing and persistent reliability issues, for whom high per customer costs may prevent improvements. Values have been set with regard to containing total scheme cost within the amount that customers are willing to pay, noting the inherent variability of scheme costs (see Box 6).

Box 6: GSL scheme costs

Current scheme

Currently, $10.1 million per annum ($12 per year, per customer) is recovered from consumers through distribution tariffs for the GSL scheme.[87] Over the last 13 years, the average cost of the scheme has been $4.8 million.

The AER's allowance of $10.1 million per annum was made with reference to a single base year (2013-14). In that year, GSL payments were the highest to date. The average cost up until 2013-14 (from 2005-06 to 2012-13) had been $2.3 million.

The cost of the GSL scheme is highly variable. In the 2015 – 2020 period so far, average annual costs were $10.7 million: $2.5 million in 2015-16, $28.4 million in 2016-17, and $1.3 million in 2017-18.[88]

Changes to network reliability payments[89]

With the changes set out in this final decision, the cost of network reliability payments will still be highly variable. For example, in the 2015 – 2020 period so far, average annual costs of total duration payments are estimated to have been $6.1 million:

- $0.9 million in 2017-18 (compared with $1.0 million for the duration component of the current GSL scheme)
- $16.0 million in 2016-17 (compared with $27.5 million for the duration component of the current GSL scheme), and
- $1.4 million in 2015-16 (compared with $2.4 million for the duration components of the current GSL scheme).

Marked differences between individual years will continue. How to provide for this in revenue determinations is an important consideration for the AER.

Frequency payments will be simplified

Frequency payments already relate to reliability over time, which makes them well targeted to customers who experience ongoing or persistent reliability issues. From 1 July 2020, there will be one level of frequency payments instead of three, further reducing the overall cost of the GSL scheme.

[87] Guaranteed Service Level scheme costs are included in SA Power Networks' operating expenditure allowance determined by the Australian Energy Regulator. The most recent operating expenditure allowance was set with reference to 2013-14 as a base year, in which GSL payments were $10.1 million. (See Australian Energy Regulator, *SA Power Networks Determination 2015-16 – 2019-20 Final Decision – Attachment 7 Operating Expenditure*, October 2015, p. 64).

[88] Values are nominal, as reported to the Commission by SA Power Networks each year for the last 13 years.

[89] These estimates are based on analysis by the Commission and SA Power Networks.

In sum, the revised payments have the effect of capping payments to any one customer, in any one year. The maximum amount any one customer can receive based on total duration of interruption is $300 per annum. They may also receive a frequency payment ($100), if eligible, making a total of $400 per annum. The overall costs of changes to network reliability payments are discussed in Box 6.

Current exclusions will continue

There are currently a number of interruptions that are excluded in calculating network reliability GSL payments. These are:

- interruptions causes by transmission and generation failures
- disconnections required in an emergency situation (for example, a bushfire)
- single customer faults caused by that customer
- momentary interruptions (currently defined as those longer than one minute, to be redefined as those longer than three minutes from 1 July 2020), and
- planned interruptions.

In addition, if an interruption occurs that is beyond the control of SA Power Networks (for example, bushfire, lightning, storm, flood), and it is unsafe to restore supply, that time is excluded for the purpose of calculating GSL payments. The Code was amended to clarify this exclusion in January 2018.[90] These exclusions will continue to apply after 1 July 2020.

4.1.1 Submissions to draft decision

Four submissions to the draft decision address changes to network reliability GSL payments.

SA Power Networks supports the proposed changes. It agrees that total annual duration payments will better target customers who consistently receive poor reliability outcomes. However, SA Power Networks argues for a further exclusion to calculation of network reliability payments – interruptions on MEDs. Its rationale is that: outages on MEDs may contribute to customers receiving a total duration payment, where that customer usually has sound reliability; and, that interruptions on MEDs are not within the reasonable control of SA Power Networks.

Business SA notes that the changes in payment levels for very long outages are material, and need to be carefully considered. Business SA advises that care be taken with low reliability feeder customers, given that the draft decision both proposes not to make specific reliability standards for that customer group, and also to reduce the value of duration payments (of which, historically, 37 percent have been made to low reliability feeder customers).

The Energy Security for South Australia Working Party, regarding payment levels for total duration payments and frequency payments, questions whether 'payment values provide an adequate incentive for SA Power Networks to improve this low reliability.'

SACOSS strongly supports the revisions to network reliability payments, on the basis that they will reduce the overall costs of the scheme. SACOSS supports the Commission's interpretation of the customer survey results meaning that 'customers are willing to pay less [for duration GSLs] than they do now'. SACOSS supports both the Commission's 'methodology and detailed consideration of the balance between customer expectations and the need to contain costs'.

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[90] Essential Services Commission of South Australia, Electricity Distribution Code Clarification, January 2018, available at https://www.escosa.sa.gov.au/projects-and-publications/projects/electricity/electricity-distribution-code-clarification.

SACOSS notes the highly variable nature of GSL scheme costs, agrees with the Commission that this is likely to continue, and submits that the AER needs to consider how to provide for this in its revenue determination.

Further, although SACOSS previously submitted (in its submission to the Review's Objectives and Process paper) that payments for interruptions on MEDs should be excluded from the GSL scheme, it accepts the Commission's analysis that further exclusions present a communication challenge.

Although it did not make a formal submission to the draft decision, EWOSA has indicated its support for replacing duration payments with total duration payments, simplifying frequency payments, and for the changes to payment levels.

4.1.2 Rationale

As already discussed, the Commission is of the view that a jurisdictional GSL scheme is beneficial, as it allows local conditions, and the preferences of South Australian customers, to be accounted for.

Customers are not willing to pay as much as they do now for network reliability payments, and many customers are unwilling to pay anything at all. Aggregate willingness to pay, in the survey conducted for this Review, is $6.4 million per annum. Currently, customers pay $10.1 million per annum.

Therefore, the Commission has decided to make changes to contain the cost of network reliability payments, which also better target network reliability payments to those for whom they are intended: those with ongoing, persistent reliability issues.

Should payments apply in relation to MEDs?

SA Power Networks argues that interruptions on MEDs should be excluded in calculating network reliability payments. Several submissions to the Objectives and Process paper supported this approach. [91]

When this option was put to directly to customers in the Review's customer survey, results were mixed. Customers were asked whether they would support removing GSL payments for long outages due to major storms, on the basis that it would reduce annual costs of the GSL scheme from $12 per customer to $2 per customer. Results were that 45 percent of customers would not support this change, 41 percent would, and 14 percent did not know.

This exclusion would be challenging to explain. The experience of South Australian customers in understanding other exclusions to the GSL scheme, such as outages caused by transmission and generation failure (in relation to the September 2016 state-wide outage, and load shedding in February 2017), and emergency circumstances (in relation to the December 2016 storms), highlights the potential communication challenge.[92] In its submission, SACOSS accepts the Commission's reasoning on this matter.

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[91] Part of the rationale for considering this is that SA Power Networks has limited ability to control payments that relate to major event days, through either capital investment or operational decisions. As SA Power Networks has limited ability to predict which area severe weather will affect, it cannot predict where the majority of Guaranteed Service Level payments will be required. If SA Power Networks chose to undertake widespread network investment, or increased operating expenditure, to manage Guaranteed Service Level payments on major event days, the costs would far exceed the benefits.

[92] In addition to exclusion of outages caused by transmission or generation failure, outages (or parts of outages) are excluded when SA Power Networks cannot gain safe access (see section 2.3.2 of the Code). Due to the exclusion of outages caused by transmission and generation failure from the Guaranteed Service Level scheme, SA Power Networks was not required to make payments for some recent notable outages, including the 28 September 2016 state-wide outage and the rotational load shedding of 8 February 2017. Due to limited access in emergency circumstances, SA Power Networks was not required to make payments for all outages that resulted from the December 2016 storms. Complaints to the Energy and Water Ombudsman of South Australia regarding Guaranteed Service Level payments increased from 13 in 2015-16 to 138 in 2016-17.

Impact on low reliability feeder customers

Business SA notes that the changes in payment levels for very long outages are material, and will particularly affect customers on low reliability feeders. (Since 2010, 37 percent of duration payments have been made to customers on low reliability feeders, who represent three percent of the customer base). It also notes these customers will be affected by the Commission's decision not to introduce reliability standards specifically for low reliability feeders.

The Commission acknowledges that the value of total duration payments will be lower than the value of duration payments. However, it expects that overall, more payments will be made to relevant customers. Not only will customers who have one-off outages but typically good reliability be 'left out' of the scheme, customers who have multiple outages less than 12 hours long, but longer than 20 hours in total, will now be captured.

Further, the threshold structure for total duration payments recognises the cumulative impact of outages. While the highest threshold for current one-off duration payments is > 48 hours, the highest threshold for total annual duration payments is > 60 hours.[93]

The Commission has deliberately separated its decisions on network reliability GSL payments and reliability standards for low reliability feeders. Network reliability payments are available to all customers who experience ongoing and persistent reliability issues, whether there are one or two on a feeder, or all customers on a feeder have poor reliability.

Reliability standards for low reliability feeders would encourage network improvements, which would be made on specific feeders, and affect specific and concentrated groups of customers. Customer's willingness to pay for network reliability GSL payments ($6.4 million pa) and willingness to pay for improvements to low reliability feeders ($1.9 million pa) relate to different options for the reliability standard framework.

Consideration of payment levels

The value of network reliability payments has been set with regard to containing the overall cost of the scheme (see Box 6), and containing payment values within the annual distribution costs included in a typical residential bill (approximately $545 per annum).[94, 95]

93 Following the December 2016 storms, the then Minister for Energy and Mineral Resources asked the Commission to examine whether the Guaranteed Service Level scheme should be expanded to include increased payments for power interruptions more than three days (72 hours) long. In considering this, the Commission found that very few single unplanned interruptions last longer than 72 hours. There would have been 1001 payments for a 72-hour plus threshold following the December 2016 storm (out of the total 65,227 duration payments). From 2010-11 to 2012-13 there were, on average, only six duration payments made each year for interruptions longer than 72 hours.

94 Figure based on quarterly distribution network charges figure provided by SA Power Networks of $136, for a residential customer consuming 1250 kWh per quarter.

95 The Commission considered values calculated with reference to the Australian Energy Market Operator Value of Customer Reliability (these would be $460, $700 and $1390 respectively), noting the Australian Energy Market Operator Value of Customer Reliability Application Guide notes limitations in the use of the Value of Customer Reliability for long outages. These calculations are for a residential customer consuming 1250 kWh per quarter, and a Value of Customer Reliability of $40.62 per kWh.

Total duration payments in the STPIS GSL scheme have the same thresholds (20, 30 and 60 hours) and values ($100, $150 and $300) as set out in this final decision.[96] Total duration payments also apply in Victoria, with the same thresholds and slightly higher values ($120, $180 and $360).[97] The STPIS GSL scheme was reviewed in 2018, and the Victorian scheme in 2015.[98]

The value of frequency payments has been considered with regard to current values in the South Australian scheme ($100 - $200, depending on the number of interruptions), and the value of frequency payments in the STPIS scheme ($80, for more than nine interruptions on CBD or urban feeders, and for 15 or more interruptions on rural feeders).

Payments do not drive restoration times

The Commission recognises the Energy Security for South Australia Working Party's concern that GSL payments should incentivise reliability improvements. The GSL scheme aims to recognise that, in many cases, the cost of network improvements is greater than their benefit. Further, following interruptions SA Power Networks takes a structured approach to restoring power, as set out in Box 5, on which network reliability payments have limited impact.

4.2 Late attendance at appointments

The final decision is to remove the GSL payment for late attendance at appointments.

This final decision is consistent with the draft decision to remove the GSL payment for late attendance at appointments. Currently, a payment of $25 applies if SA Power Networks is more than 15 minutes late for an appointment, unless lateness is due to circumstances beyond its reasonable control.[99]

4.2.1 Submissions to draft decision

Only the SA Power Networks submission specifically addresses this decision point. It supports removing the GSL payment for late attendance at appointments, and agrees with the Commission's reasoning.

4.2.2 Rationale

SA Power Networks makes few payments for late attendance at appointments. It made one late attendance payment in 2016-17 and two in 2015-16. This is because SA Power Networks now has few direct appointments with customers, which has changed since initial design of the GSL scheme. Appointments that are made (for example, for some meter reads, or to bring supply to a new connection point) are for long windows (for example, six-hours, or morning/afternoon). Further, late attendance for connection appointments is captured under the 'timeliness of new connection' GSL payment.

96 Australian Energy Regulator, *Service Target Performance Incentive Scheme*, p. 19.

97 Essential Services Commission of Victoria, *Review of the Victorian Electricity Distributors' Guaranteed Service Level Payment Scheme Final Decision*, 2015, available at https://www.esc.vic.gov.au/sites/default/files/documents/721d99ec-9f7d-4bdd-af7c-6e88647a64b1.pdf.

98 A review is also currently underway in Queensland. The consultation paper includes a useful summary of Guaranteed Service Level schemes that apply in each jurisdiction. (See: Queensland Competition Authority, *Review of Guaranteed Service Levels to apply in Queensland from 1 July 2020 Consultation Paper*, 2018, available at http://www.qca.org.au/getattachment/3e6ec027-2ad3-4e3c-be1d-d9c22141abdf/QCA-GSL-Review-consultation-paper.aspx).

99 Electricity Distribution Code 12.1, section 2.3.1(a).

4.3 Timeliness of new connections

The final decision is to continue the GSL payment for timeliness of new connections.

SA Power Networks will be required to use its best endeavours to provide infrastructure to enable a connection for a customer's new supply address on the date agreed with the customer or within six business days of the customer meeting necessary conditions. SA Power Networks will be obliged to pay a customer $65 for each day it is late in making a connection, up to a maximum of $325.[100]

This final decision is consistent with existing arrangements, and the draft decision, except that SA Power Networks' role in making a new connection is clarified to reflect new metering requirements. The wording 'provide infrastructure to enable a connection for a customer's new supply address' will replace 'to connect a customer's new supply address'.

4.3.1 Changes to metering services

Since December 2017 retailers have been responsible for metering services. As mentioned in the draft decision, this resulted in many customers experiencing delays with installations.

SA Power Networks' responsibility is to bring power to the connection point (meter isolator), the boundary of the distribution network, regardless of whether a meter is installed and operating.

The draft decision indicated that changes to this GSL payment may be required as metering contestability changes continue to rollout in South Australia. Since the draft decision was published, several changes have occurred.

In December 2018, the AEMC published its final rule change for metering installation timeframes.[101] It requires that, for small customers, meters must be installed by a date agreed with that customer. If no date can be agreed, installations must occur within six business days for a new connection.

Further, retailers have voluntarily introduced payments for failing to meet metering installation timeframes. For example, Origin and Energy Australia have a late installation payment of $175 a day and AGL of $250 a day. Both of these changes seem likely to address the timeliness of meter installations.

4.3.2 Rationale

It is important that SA Power Networks continues to provide infrastructure to enable connection of a customer's new supply address in timely manner. If this is not done, customers are inconvenienced. No changes to this payment are required, other than clarifying SA Power Networks' role.

4.4 Repair of faulty street light(s)

The final decision is to continue the GSL payment for repair of faulty street lights, and to further clarify when the five or ten day period to which payments apply begins.

This reverses the draft decision, which was to remove the GSL payment for repair of faulty street lights (**street light payment**) and replace it with a timely street light repair service standard and performance target, so avoiding the cost of street light payments, or an alternative such as night patrols. [102]

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[100] Electricity Distribution Code 12.1, section 2.3.1(b).

[101] Australian Energy Market Commission, *Final Rule Determination, National Electricity Amendment (Metering installation timeframes) Rule 2018 and National Energy Retail Amendment (Metering installation timeframes) Rule*, 6 December 2018, available at https://www.aemc.gov.au/sites/default/files/2018-12/Final%20Determination.pdf.

[102] The costs of undertaking street light repairs would still be funded by customers, as they are now, though the Guaranteed Service Level payment would be avoided.

The payment applies in addition to the existing requirement that SA Power Networks use its best endeavours to repair street lights that have gone out and for which it is responsible within five business days for metropolitan areas, and within ten business days for non-metropolitan areas.

The payment applies to the first person to report a faulty street light, and is $25 for each period (five or ten business days depending on location) in which the street light is not repaired.[103]

The Code will be amended to further clarify when each five or ten day period begins, as follows. The day on which a report is made is day zero.

Where a report is made on a business day, day zero also needs to be defined in terms of the time of the day on which the faulty street light was reported:

- For reports made through SA Power Networks' Street Lights Fault Line – on the date of the business day.
- For reports provided by other means (eg online) before 4pm – on the date of the business day.
- For any reports provided by other means after 4pm – on the date of the next business day.

These details were published by the Commission in 2010 but are not expressly reflected in the Code. When a report is made on a Saturday, Sunday, or public holiday, it is deemed to occur on the next business day.[104]

The Code will be further amended to include a definition of a street light fault. It will define a street light fault as an occasion on which a street light has gone out as a result of a fault in the luminaire, which includes the globe, photoelectric cell, and the wiring to the luminaire block. This is the definition that was set out by the Commission in 2010.

For the avoidance of doubt, the Code will clarify that instances of damage to street lights where the light has not gone out (eg damaged or missing lighting covers, or damaged poles) are not street light faults.

4.4.1 Submissions to draft decision

The draft decision was to remove the street light payment and replace it with a timely street light repair service standard and performance target. The Commission noted that:

- since the payment was introduced, it has become easier to report street light outages, with SA Power Networks introducing and improving reporting through its website.
- many customers are unwilling to pay for existing levels of duration GSL payments, and reliability improvements more generally. (The draft decision acknowledged this result could be applied only indirectly to street light payments).
- SA Power Networks had raised the issue that the street light payment has led to high levels of reporting by some individual customers, as well as instances of deliberate damage to street lights in order to receive payments.

Two submissions to the draft decision address the proposal to remove the street light payment.

The SA Power Networks' submission supports removing the street light payment. SA Power Networks further advocates that, if the Commission retains the payment, it be simplified to apply only to customers whose supply address is adjacent to the light, and only as a one-off payment (not recurring every five or ten days).

[103] Electricity Distribution Code 12.1, section 2.3.1(c).
[104] This is already set out in the Electricity Distribution Code 12.1, section 2.3(c)(i).

One submission was made by an individual who has reported 14,000 street light outages since 2012. This street light reporter argues against removing the payment, noting it has been their main motivation to report street light outages. They argue that relying on public reports will not work, and there must be a deliberate mechanism to gather information about street light outages.

They note that to maximise their street light outage reports, and so street light payments, they look to areas with older infrastructure, lower socioeconomic status, and industrial areas. They suggest that, in particular, altruistic public reports from these areas are unlikely to be sufficient.

The street light reporter notes that 'it's not clear how a large number of street light outage reports by an individual justifies the removal of the GSL [payment], if public lighting reliability is the objective'. They point out that the number of reports is 'directly related to the number of unserviceable street lights that are in the network'.

The street light reporter raises a further issue, based on their records of street light reporting and repair since 2012. When they have checked repairs to lights they reported, some 18 percent have still been out. They note instances where the same outage 'has been reported numerous times, with up to 10 reports being made for the same light before a successful repair was made'.

Additional information

Since the draft decision was published, additional consultation has identified mixed views on removal of the street light payment, and issues about service levels for public street lighting have emerged. There are three relevant matters.

First, although EWOSA did not make a formal submission to the draft decision, it has expressed reluctance to support removing the street light payment. It is concerned that the proposed alternative, a service standard and performance target, would not provide sufficient incentive for SA Power Networks to complete timely repairs, and not ensure adequate street lighting for public safety.

Second, more information is needed about how service levels for public lighting will be defined from 2020, following the AER's service reclassification. Currently, the AER classify SA Power Networks' public lighting as a negotiated distribution service.[105] This means that prices and service levels of public lighting are negotiated between SA Power Networks and its customers (local governments and the Department of Planning, Transport and Infrastructure). While the AER defines the negotiating framework, it does not directly regulate prices or service levels.

From 2020, the AER will instead classify public lighting services as alternative control services, meaning that it will determine price caps for public lighting services.[106] Service levels affect the costs of public lighting, and are relevant when determining price caps.

Where jurisdictional service standards exist, SA Power Networks must comply with those standards and so the AER must consider the efficient costs required to meet those standards.[107] The only current jurisdictional requirements are the Commission's street light payment, and its broader requirement that SA Power Networks complete repairs in a timely manner.

[105] Australian Energy Regulator, *SA Power Networks – Determination 2015 – 2020 – Overview*, October 2015, p. 54, available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020/final-decision.

[106] Australian Energy Regulator, *Final Framework and Approach, SA Power Networks Regulatory Control Period Commencing 1 July 2020*, July 2018, pp. 34 - 39, available at https://www.aer.gov.au/system/files/AER%20-%20SA%20Power%20Networks%202020-25%20-%20Final%20framework%20and%20approach%20-%20July%202018.pdf.

[107] A further street lighting requirement is that it is designed and installed in line with an Australian Standard for Lighting for Roads and Public Spaces (AS 1158), which includes requirements about lighting maintenance.

Further definition of service levels may be required for the AER to determine price caps. Two other jurisdictions where public lighting is an alternative control service, New South Wales and Victoria, have public lighting codes in place that cover a wide range of service aspects.[108]

It is expected that SA Power Networks' revenue proposal to the AER, which will be submitted by 31 January 2019, will detail the public lighting service levels it will offer from 1 July 2020.[109]

Third, street light technologies are changing. Light Emitting Diode (**LED**) fittings are replacing traditional technologies. SA Power Networks has advised that of the 220,000 street lights operated or maintained by SA Power Networks, around 45,000 are now LEDs. SA Power Networks estimate that all 220,000 street lights will be LEDs within four to five years. This will impact the reliability of street lights, as LEDs have longer lifespans (around 20 years). SA Power Networks advises it will also impact the availability of spares for older lights during the transition, with spares being limited.

4.4.2 Rationale

To remove or simplify the street light payment, it is necessary to clarify its purpose. The main purpose of the payment, according to the Commission's previous decisions, is to provide an alternative to using night patrols to identify street light outages.[110, 111] It has also been referred to as a customer service gesture.[112]

With regards to it providing an alternative to night patrols, the draft decision proposal was to remove the payment and rely on members of the public to report outages without a payment. Mixed views on this approach were obtained in submissions and consultation.

A different possibility, with regards to it providing an alternative to night patrols, is that the street light payment may be a one-off reporting payment, and not linked to ongoing periods of time the light remains unrepaired, as suggested by SA Power Networks in its submission.

With this purpose, it is reasonable that a single person can make multiple reports. If the payment's purpose is obtaining information about which lights are out, what is important is that only one payment is made per light, not that only one payment is made per customer. Further, it may be SA Power Networks that is best placed to propose the most efficient mechanism for obtaining information about faulty street lights (whether through patrols, spotter's fees or an alternative).

If the payment's purpose is simply to provide a customer service gesture, street light payments may be limited to those most affected by an outage (for example, those with a home or business adjacent to the light), as suggested by SA Power Networks in its submission. This approach is taken interstate, where street light payments are restricted to occupiers of property neighbouring the street light.[113]

However, the street light payment has functions beyond those articulated by the Commission in its past decisions. It is currently the only regulatory measure which defines public lighting service levels in South Australia.

108 Essential Services Commission of Victoria, *Public Lighting Code*, 2015, available at https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-codes-guidelines-policies-and-manuals/public-lighting-code, New South Wales Department of Planning and Environment, *New South Wales Public Lighting Code*, September 2018, available at https://energy.nsw.gov.au/sites/default/files/2018-10/Final%20-%20Public%20Lighting%20Code%20-%20Clean.PDF.

109 SA Power Networks, *2020 – 2025 Draft Plan*, 2018, p. 77.

110 Essential Services Commission of South Australia, 2*005 – 2010 Electricity Distribution Price Determination Part A: Statement of Reasons*, p. 51.

111 Essential Service Commission of South Australia, *SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period Draft Decision,* p. 34.

112 The Office of the South Australian Independent Industry Regulator, *Service Standards for 2005 to 2010 Discussion Paper*, February 2002, p. 12.

113 Essential Services Commission of Victoria, *Public Lighting Code version 2,* 2015, section 2.5, available at https://www.esc.vic.gov.au/document/energy/29284-public-lighting-code-current-version/.

The need to define public lighting service levels may change, as the AER will consider public lighting as an alternative control service, rather than a negotiated service, in the new regulatory period. This means that the AER will establish price caps for public lighting services, and require a point of reference for public lighting service levels.

Further, the introduction of LED lighting will change the nature of street light maintenance and repairs, and so the need for reporting.

Overall, based on consideration of the above points, the Commission is of the view that more information is needed about how public lighting service levels will be defined from 2020 before the purpose of the street light payment can be clarified, and redesigned if necessary. Therefore, the final decision is to delay any changes, and continue with the payment in its current form for the 2020 – 2025 period.

More information may become available between now and the start of the next regulatory period. The Commission will seek out and consider such information, and review this decision point if it sees fit.

The Commission will separately work to address issues relating to compliance with the street light payment, including instances where lights are reported as repaired, but are still not working.

5 Customer service standards

This section addresses the third of the reliability standard framework's four main elements: customer service standards and targets. Customer service is important because its quality influences how customers experience power outages, and because SA Power Networks relies on information from customers to identify and locate outages.[114]

Customer service measures currently relate to SA Power Networks' responsiveness to telephone and written enquires. However, SA Power Networks also communicates with its customers by email, through its website, Power@MyPlace app, SMS messages, social media (currently Facebook and Twitter) and other media (print, radio and online).

In its 2014 final decision on customer service standards for 2015 – 2020, the Commission noted that as 'customers become more reliant on other communications channels to report supply interruptions, the current focus on telephone responsiveness may need to be revisited'.[115]

Although telephone communication remains vital to SA Power Networks' business, use of other channels, and customer reliance on other channels, has escalated since 2014.

5.1 Telephone responsiveness standard updated

The final decision is to retain the telephone responsiveness standard, with an updated definition.

This final decision is to retain the telephone responsiveness standard, which is that SA Power Networks is obliged to use its best endeavours to respond to 85 percent of telephone calls within 30 seconds. This target applies to average annual performance, in normal operations.

The final decision is that the definition of responding to telephone calls will be updated to be:

a) answering a customer's telephone call in person. Where a caller to an Interactive Voice Response (IVR) system is seeking to talk to an operator, then monitoring of the call waiting time should commence when the caller selects the relevant operator option and cover the resulting time up and until an operator picks up the call, to deal with the caller's issue; and

b) answering a customer's telephone call by providing access to a computer/telephony based interactive service which is able to process calls by providing information or directing calls to a service officer.

5.1.1 Submissions to draft decision

No submissions to the draft decision specifically address the telephone responsiveness standard.

5.1.2 Rationale

Telephone contact continues to be important for customers. Though contact through other channels has increased, the number of telephone calls has not declined.

[114] Equivalent customer service standards for National Energy Retail Law retailers were transferred to the Australian Energy Regulator with the commencement of the National Energy Customer Framework, but responsibility for administering SA Power Networks' customer service standards and targets remains a jurisdictional requirement.

[115] Essential Services Commission of South Australia, *SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period Final Decision*, p. 20.

The current standard focuses on SA Power Networks' responsiveness to the calls received, so it is important that the time customers are required to wait is accurately captured. A call is only considered to be 'answered' when the customer has been able to start to resolve their query, whether that is through talking with a person or through automated self-service options.

The current Code definition of 'responding to telephone calls' is potentially ambiguous about whether the time a customer spends waiting after the automated call answering system directs their call to a person counts towards the 30 second target.

The Code currently defines **responding to telephone calls** as:

> 'a) answering a customer's telephone call in person; and
>
> b) answering a customer's telephone call by providing access to a computer/telephony based interactive service which is able to process calls by providing information or directing calls to a service officer.
>
> but does not include the answering of a call by being placed in an automated queue to wait for one of the options above.'[116]

Electricity Guideline No. 1 G1/12 – Electricity Regulatory Information Requirements – Distribution (**Electricity Guideline No. 1**) further clarifies the Commission's expectation on responding to telephone calls:

> 'Where an IVR operates, it is not appropriate to regard the call as being answered unless the customer has selected an automated response option and does not seek to talk to an operator (note: a call is not considered to be answered by being placed in an automated queue).
>
> Where a caller to an IVR system is seeking to talk to an operator, then monitoring of the call waiting time should commence when the caller selects the relevant operator option and cover the resulting time up and until an operator picks up the call, to deal with the caller's issue.'[117]

However, this intention is not clear in reading the Code's definition in isolation. To address the potential ambiguity, the decision is to amend the current definition to include the clarification currently included in Electricity Guideline No. 1.

5.2 Written responsiveness standard retained

The final decision is to retain the written responsiveness standard.

This final decision is to retain the written responsiveness standard, which is that SA Power Networks is obliged to use its best endeavours to respond to 95 percent of written enquiries within five business days. This target applies to average annual performance, in normal operations.

The draft decision specified that this standard apply to letter, fax, and email enquiries. This detail is not included in the final decision.

5.2.1 Submissions to draft decision

No submissions to the draft decision specifically address the written responsiveness standard.

[116] Electricity Distribution Code 12.1, section 2.1.2

[117] Essential Services Commission of South Australia, *Electricity Regulatory Information Requirements – Distribution, Electricity Industry Guideline No. 1 (G1/12)*, July 2015, p. 15, available at https://www.escosa.sa.gov.au/ArticleDocuments/512/20141007-Elec-GuidelineNo1-EG12.pdf.aspx?Embed=Y.

5.2.2 Rationale

Written enquiries by email, fax or letter account for less than one percent of customer contact with SA Power Networks. Despite representing a small proportion of contact, timely response to written enquiries is important to those customers who choose this channel of communication. Further, it may become increasingly important as avenues for written communication with SA Power Networks expand.

Removing the specification that written enquiries are through letter, fax, or email allows that enquiries may also be made through other channels, such as direct messaging through social media. Measuring responsiveness to customer contact through social media is challenging. It may take different forms, such as commentary without a specific enquiry, and queries of a general nature posted publicly might be satisfactorily answered by other customers.

However, direct private messaging through social media is equivalent to written enquiries by letter, fax or email. From 1 July 2020, the definition of written enquires will be general, to allow for such alternatives. Electricity Guideline No. 1 will be updated to include direct private messaging through social media as a form of written enquiry, alongside letter, fax and email.

The Commission considered whether to establish a specific responsiveness standard for email or other electronic communication. Written enquiries by email can be responded to quickly, and customers expect a quick response.

However, genuinely considering and resolving each enquiry requires thought, so the existing timeframe of five days for a fuller response is reasonable. The Commission expects SA Power Networks will acknowledge customer emails quickly (for example,, straight away, by automated response), as part of its normal business practice.

The definition of response to written enquiries will remain the same: direct or telephone or written response in which the distributor either answers the enquiry or acknowledges receipt of the enquiry and indicates the process and timetable to be followed in dealing with the enquiry.[118]

5.3 SMS communications

The final decision is to make no specific requirements about how SA Power Networks provides information about outages by SMS.

This reverses the draft decision, which was to introduce a general requirement that SA Power Networks provide timely, current and accurate information, when it uses SMS to communication with customers about outages.

5.3.1 Submissions to draft decision

The draft decision was to introduce a general requirement, to would apply to customers who are registered to receive SMS messages.

The requirement was that SA Power Networks SMS those customers as soon as possible to: advise it is aware of an outage, advise of the outage cause, provide an estimated restoration time, and provide updates, as required, until power is restored.

[118] Electricity Distribution Code 12.1, section 2.1.5.

The draft decision did not propose to require SA Power Networks to:

- provide an SMS service – it already does so, without regulation
- set a timeframe for sending SMS messages – current practice is to message as soon as possible, typically within around 10 -15 minutes of becoming aware of an outage
- increase the number of customers for whom it holds mobile phone numbers and consents (currently around 40 percent) – it is already does so proactively, or
- undertake specific monitoring or reporting.

Three submissions to the draft decision address the proposal to introduce the SMS communication standard. The SA Power Networks' submission argues that the proposed SMS communications standard is not required. It submits that SA Power Networks already provides timely and accurate information by SMS, and that a single instance of poor performance (in relation to the December 2016 storms) does not justify regulation. It explains:

> 'We consider that there is sufficient incentive for us to provide accurate messaging to customers without imposing a service standard. It is in our interest to ensure that our messaging is as accurate as possible, and for us to continue to modify and refine our process and messages to find the best possible approach to using SMS messaging for customer benefit.' [119]

SACOSS does not see evidence, aside from issues in the December 2016 storms, that SMS information is not timely or accurate. Despite this, it cautiously supports an SMS communication standard, so long as 'customers should incur no additional costs associated with SA Power Networks complying with this new standard, as existing systems and practices are sufficient to meet the standard imposed'.[120]

The Energy Security for South Australia Working Party submission notes the proposed SMS provisions would not have improved communications during the September 2016 outages on the Eyre Peninsula, when the mobile communication network failed.

5.3.2 Rationale

SMS is an increasingly important communication channel, and it is important that information provided by SMS is timely, current and, to the extent possible, accurate.

The merit in making general provision for information provided by SMS to be timely, current and, to the extent possible, accurate would be to provide a general frame of reference for assessing performance. It would provide a reference point for assessing performance in significant events, such as the 27-28 December 2016 storms.

With regard to the December 2016 event, concern about the accuracy of restoration information provided to customers by SMS was investigated as part of the Commission's 2017 Distribution Licence Compliance Review.[121] That review reported a series of actions to improve accuracy of information sent by SMS, which SA Power Networks has since pursued.

The Commission agrees with SACOSS that, with the exception of issues during December 2016, SA Power Networks already provides quality information by SMS to registered customers.

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119 SA Power Networks submission to the Review draft decision.

120 South Australian Council of Social Services submission to the Review draft decision.

121 Essential Services Commission of South Australia, *Distribution Licence Compliance Review of SA Power Networks in Relation to the 27-28 December 2016 Severe Weather Event,* pp. 16-17.

Further, SA Power Networks expresses a desire to 'continuously improve' its SMS messaging, acknowledges that SMS messaging reduces the volume of calls to the faults and emergencies line, and is valued by customers. On that basis, the Commission expects that SA Power Networks will track internal measures of SMS quality and improvement, and could provide evidence about performance if further SMS messaging issues arise.

The Commission supports SA Power Networks expanding its use of SMS messaging as part its core business, and does not consider that regulation is required at this point.

5.4 Communication quality measure: for monitoring

The final decision is to require SA Power Networks to monitor and report on a communications quality measure, as agreed with the Commission.

This final decision to require SA Power Networks to monitor and report on a communications quality measure. This is consistent with the draft decision, and there is no current standard or performance target for communication quality.

Initially, the measure will be the Customer Service Benchmarking Australia customer service measure and its sub-measures (for planned and unplanned interruptions, new connections and complaints).

5.4.1 Submissions to draft decision

One submission to the draft decision, from SACOSS, addresses the proposal to introduce a communication quality measure. SACOSS argues that there is not a clear need for this measure, 'in the absence of real evidence of consumer dissatisfaction with SA Power Networks communications quality'. SACOSS is concerned that customers may bear the costs of SA Power Networks meeting the standard.

5.4.2 Rationale

Responsiveness is only one element of customer service, and responsiveness measures (timeframes for answering enquiries) do not capture communication quality.

Communication quality measures cut across communication channels, and can capture use of hard to measure channels like social media. The Commission has considered standards for social media and Internet communication. Developing measures for these channels that are robust, and will endure over time, is challenging. For example, while SA Power Networks tracks the inbuilt customer responsiveness and satisfaction measures on Facebook and Twitter, commonly used social media platforms are likely to change over time, making them unsuitable to include in the reliability standards framework.

In Australia, the composite measure developed by Customer Service Benchmarking Australia is being increasing adopted by electricity distributors and water utilities.[122] This measure captures satisfaction and ease of overall experience in four areas (planned and unplanned interruptions, new connections and complaints), and as an aggregate score. It allows comparison over time, and benchmarking against interstate utilities. SA Power Networks has recently engaged Customer Service Benchmarking Australia to measure its communication quality using this composite measure.

The communication quality measure does not oblige SA Power Networks to undertake any additional activities. SA Power Networks is already engaged with the task of ensuring, and measuring communication quality.

[122] AusNet Services, TasNetworks and the Australian Gas Infrastructure Group also use this tool.

The Commission supports SA Power Networks understanding and improving its communication quality, and reiterates that, at this point, this measure is for monitoring only. It does not form the basis of a service standard or performance target. The Commission does not expect this modest communication standard to result in additional effort, reporting, or costs.

6 Performance monitoring and reporting

This section addresses the fourth of the reliability standard framework's main elements: performance monitoring and reporting.

Performance monitoring and reporting promotes transparency. It informs customers about the level of service they are receiving (at an aggregate level) and identifies reasons for variation in performance. Public scrutiny provides SA Power Networks with an incentive for improvement. It also provides data required to develop reliability standards, assess compliance, and inform the decision-making processes of regulatory agencies, regulated businesses and government.

Currently, the Commission has a standing data request of SA Power Networks, in the form of Electricity Industry Guideline No. 1. The Commission makes additional information requests as required (for example, regarding significant performance reporting, or to make best endeavours assessments when performance targets are not met).

Information submitted by SA Power Networks currently forms the basis of a series of reports, published by the Commission, on SA Power Networks' performance. These are:

- Quarterly operational and performance reports. These brief reports provide an indication of customer service and reliability performance in relation to annual targets, and of GSL payments.
- Annual regulatory performance reports. These more detailed reports describe longer-term trends in customer service, reliability performance and GSL payments. They discuss in detail performance issues and the impact of severe weather events.
- Significant performance event reports. These reports describe performance relating to significant events, such as an event that causes extended outages for a large number of customers. In 2017, the Commission published a significant performance event report in relation to the 28 September 2016 and 27-28 December 2016 outages.[123, 124]

This final decision introduces an enhanced reporting and monitoring regime, with several changes to current performance monitoring and reporting arrangements.

The high level elements of each are set out below. There will be further development between now and 1 July 2020. This will occur through the Commission's current reviews of both its general reporting regime and its monitoring and evaluation framework and the revision of Electricity Guideline No. 1.

Electricity Guideline No. 1 will be revised to reflect the Commission's decision on reliability standards for 2020 – 2025. It will continue to require reporting on customer service, reliability of supply, the GSL scheme, statistical information, embedded generation, and requirements of the South Australian Government's Office of the Technical Regulator. Those data are required to enable the Commission to undertake ongoing analysis of performance.

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[123] Essential Services Commission of South Australia, *Distribution Licence Compliance Review of SA Power Networks in Relation to the 27-28 December 2016 Severe Weather Event.*

[124] Historically, the Commission reported on summer performance each year from 2006-07 to 2009-10 (as *Summer Distribution Network Performance Reports*).

6.1 Reporting on ten regional categories

The final decision is to expand the number of regions for which the Commission requires reporting from seven to ten.

The ten regions for which reporting will be required are the same as those proposed in the draft decision as the basis of network reliability standards. The ten regions are nine distinct geographic regions, and a tenth category for major regional centres (MRCs). These are set out in Table 7, which also compares each with the seven regions the Commission currently uses for reporting, and SA Power Networks' network planning regions.

Table 7: Regional categories for enhanced reporting regime

Regional category	Definition, with respect to current Commission reporting regions	Aligned SA Power Networks' planning regions
Adelaide Business Area (ABA)	ABA boundary revised to reflect development in the CBD since 1999, as shown in Figure 5.	Adelaide Central Region
Adelaide Metropolitan Area (AMA)	Major Metropolitan Area (Adelaide feeders only), plus agreed feeders in Gawler.	Metro East, Metro West, Metro North and Metro South
Major Regional Centres (MRCs)	Agreed feeders in Urban Centres and Localities with a population of 10,000 or more at the 2016 census, except Adelaide and Gawler. Currently, select feeders in Mount Barker, Port Augusta, Port Lincoln and Whyalla are included in the Major Metropolitan Area Code reporting region.	Included in individual planning regions
Barossa, Mid-North and Yorke Peninsula	As per existing 'Barossa, Mid North, Riverland and Murraylands' reporting region, with the Riverland and Murraylands excluded to become a separate region, and with agreed feeders in Gawler excluded and incorporated in the AMA.	Barossa, Mid-North, Yorke Peninsula
Eastern Hills	As per existing 'Eastern Hills and Fleurieu' reporting region, with Fleurieu excluded to become a separate region.	Eastern Hills
Eyre Peninsula	As per existing 'Upper North and Eyre Peninsula' reporting region, with the Upper North excluded to become a separate region.	Eyre
Fleurieu Peninsula	As per existing 'Eastern Hills and Fleurieu' reporting region, with Eastern Hills excluded to become a separate region, and the addition of Kangaroo Island.[125]	Fleurieu Peninsula

[125] Kangaroo Island is included in the new Fleurieu Peninsula region. This is justified by improvements in reliability performance on Kangaroo Island over the last decade. For the 2010 – 2015 regulatory period, a specific target was set for Kangaroo Island as a special case. Historical reliability performance of the Kangaroo Island distribution network indicated that there was a problem associated with reliability of electricity supply to the Island. Average duration of outages were typically three to five times greater than on other parts of the rural network in South Australia. The characteristics of the Kangaroo Island network, and the environment in which it is located, also contributed to this problem. As a result, a specific target was set for the Island, on the basis that its particular characteristics and the historical performance experienced by customers justified special treatment. The target was achieved.

Regional category	Definition, with respect to current Commission reporting regions	Aligned SA Power Networks' planning regions
Riverland and Murraylands	As per existing 'Barossa, Mid North, Riverland and Murraylands' reporting region, with the Barossa and Mid North excluded to become a separate region.	Riverland and Murraylands
South East	No change	South East
Upper North	As per existing 'Upper North and Eyre Peninsula' reporting region, with the Eyre Peninsula excluded to become a separate region.	Upper North

Adelaide Business Area

The Adelaide Business Area (ABA) boundary will be revised to reflect development in the CBD since the Code came into effect in 1999. The revised boundary is shown in Figure 5, together with the current boundary.

Since 1999, there has been substantial development to the south and west of the current boundary, and development on the north-west corner including the new Royal Adelaide Hospital and medical research facility.

The purpose of reporting on the ABA as a distinct region is to make performance transparent, for customers and other stakeholders. Customers should be able to recognise which region they are in.

This is challenging for the ABA. Adelaide's business area is sometimes considered as the square mile bounded by the North, South, East and West Terraces. The square mile includes a mix of business and residential functions.

In redefining the ABA boundary, the focus has been aligning it with the type of capital city functions typically concentrated in the centre of state capitals. The draft decision proposed a boundary based on the land use zones defined by Adelaide City Council, which reflect current and allowable land use.[126] The proposed boundary used the edges of Adelaide City Council's Capital City Zone, Riverbank Zone, and Institutional Zones above North Terrace.

In its submission to the draft decision, SA Power Networks agrees with the Commission's justification for expanding the ABA boundary, and disagrees with the inclusion of two small portions. These are:

- the area bounded by Grote Street, Gouger Street, Morphett Street and West Terrace; and,
- the area along West Terrace, between Grote Street and South Terrace.

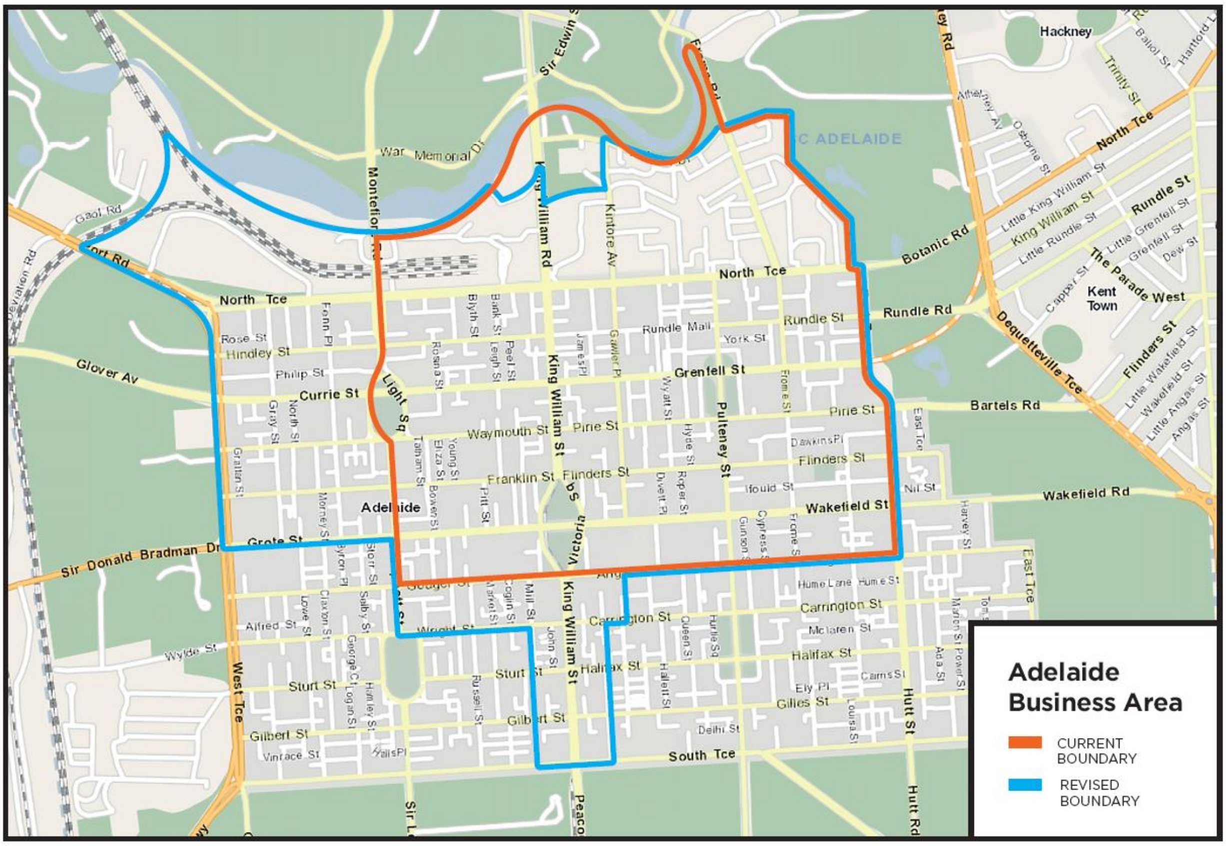
The Commission has reviewed these areas, and agrees with SA Power Networks' analysis. These two areas differ from other parts of the ABA: they do not have capital city functions.

The first area consists of a mixture of residential and low-rise commercial uses, including restaurants, workshops and showrooms, and a four-storey Australia Post depot. Land uses in the area immediately to the north (between Grote Street and Franklin Street), which remains in the revised ABA, though similar, are changing – it contains several high-rise developments.

[126] Adelaide City Council, *Adelaide (City) Development Plan Zone Map Gazetted 30 May 2017*, 2017, available at https://www.cityofadelaide.com.au/assets/documents/MAP-development-plan-zone.pdf.

The second area consists of car dealerships, restaurants, and some low-rise offices. The area along West Terrace between Grote Street and North Terrace, despite having similar land uses, remains in the revised ABA, due to the nature of land use immediately behind that part of West Terrace (more high-rise, commercial development).

Figure 5: Revision to boundary of the Adelaide Business Area



Source of underlying map: Location SA Map Viewer, http://www.location.sa.gov.au/viewer/

Major regional centres

The MRC category will include agreed feeders in Urban Centres and Localities with a population of 10,000 or more at the 2016 census, except Adelaide and Gawler.[127] SA Power Networks' initial estimate is that this category may contain 80,000 customers.

This category has been introduced because on average, MRCs have significantly better reliability than both the non-urban parts of regional areas, and metropolitan Adelaide. Depots are often located in these centres, and local networks are small, and relatively simple.

To illustrate, the average USAIDI from 2012 – 2017 for the Eyre Peninsula excluding Port Lincoln and Whyalla (MRCs) was 450 minutes. With Port Lincoln and Whyalla included, average USAIDI was 235 minutes.

[127] These are Crafers-Bridgewater, Mount Barker, Mount Gambier, Murray Bridge, Port Augusta, Port Lincoln, Port Pirie, Victor Harbor, and Whyalla. Urban Centres and Localities are defined by the Australian Bureau of Statistics: see http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/05773C1D8C9F2022CA257A98001399F7?opendocument

6.1.1 Submissions to draft decision

As noted in section 3.3.4, submissions to the draft decision from Business SA, the Energy Security for South Australia Working Party and SACOSS each support the proposal to introduce regional reliability standards, on the basis these would improve communication, accountability and transparency. The Commission considers that these benefits can be delivered through an enhanced reporting and monitoring regime.

The SA Power Networks submission to the draft decision supports reporting for ten regions, despite not supporting regional reliability standards. SA Power Networks notes that it can complete this reporting with minimal cost, so long as 'the basis for recording an interruption remains aligned with our reporting obligations under other regulators' reliability reporting regimes'.[128]

SA Power Networks is concerned about the level of detail the Commission may require to be included in regional reporting. It notes: '… if we must provide reasons for normal variations in performance in a region's reliability, our reporting costs will significantly increase'.[129]

SA Power Networks is specifically concerned with explaining variation in regional performance, and for this reason is concerned with how regional performance data is normalised (see section 6.2).

On this matter, SA Power Networks' position is that the required method should be the IEEE method, as this is required by the AER and is a widely used industry standard. (This is also the method the Commission will require for normalising feeder category performance data).

6.1.2 Rationale

The Commission acknowledges that stakeholders are concerned with regional performance and SA Power Networks' accountability for its performance in regions. It considers that an enhanced reporting and monitoring regime can deliver the communication, accountability and transparency required to address these concerns.

Regional reporting will serve to inform individual customers, if they seek out information. It will also serve to inform other stakeholder groups, and form a relatable record of SA Power Networks' performance.

The Commission understands the need for the basis of recording an interruption to be consistent across regulators. It will therefore bring the basis in line with that required by the AER (see section 3.6). Further, it will work with SA Power Networks to settle an appropriate method for normalising performance data (see section 6.2).

The Commission's expectation is that, although the new reporting framework may require a change in how resources are used, the required data and analysis is similar to that which SA Power Networks prepares regularly for other purposes. Such data and analysis is required for SA Power Networks' day-to-day business of operating its network and engaging with its customers.

Therefore, the Commission expects that reporting on ten regions, with a wider scope, should not result in additional effort or costs.

[128] SA Power Networks submission to Review draft decision.
[129] SA Power Networks submission to Review draft decision.

6.2 Normalising regional performance data

The final decision is that the Commission will work with SA Power Networks to develop and consult publicly on an acceptable methodology for normalising regional performance data ahead of 1 July 2020.

Currently, the Commission requires that performance is normalised using the IEEE method before it is assessed against performance targets (see section 3.4).

The Commission does not specify how regional performance data should be normalised before it is included in regional reporting.

To do so, SA Power Networks uses a method it has designed, with the purpose of excluding the impact of localised significant weather events. Such weather events may significantly affect regional reliability but not be classified as a MED.[130]

6.2.1 Submissions to draft decision

In its submission to this Review's Objectives and Process paper, SA Power Networks states:

> 'The exclusion of MEDs is an effective method for normalising the performance of the whole distribution network (ie at a state-wide level)…. However, it is not as effective for normalising reliability at a sub-distribution network level (for example, regional), as a localised severe weather event (SWE) can significantly affect the reliability at sub-distribution network level but not be classified as a MED.
>
> These localised SWEs must be excluded at a sub-network level to enable effective monitoring of underlying (ie normalised) reliability at that level. Consequently, if the Commission was to impose reliability standards on a regional basis (ie sub-network level), a different normalisation method would need to be adopted, to monitor underlying reliability at a regional level.' [131]

The draft decision noted that normalising performance to assess regional performance would require reviewing the current methodology. In response, SA Power Networks' submission to the draft decision demonstrated the impact on performance data of the IEEE method, and the method SA Power Networks currently applies in preparing its regional reports.

SA Power Networks' position is that, despite its limitations in removing localised significant weather events, the IEEE method should be the Commission's requirement for normalising regional performance. This is because it is a widely used industry standard, and the method required by the AER in preparing STPIS performance data.

6.2.2 Rationale

It is important that both the reliability standards framework, and the reporting framework, separately consider underlying performance and performance during significant events. The reasons why are set out in section 3.4.

130 The method is as follows. First, SA Power Networks takes the number of system wide major event days identified using the Institute of Electrical and Electronics Engineers method. Second, it removes the same number of days from each region's performance. These are the worst days of performance, but not necessarily the same as the system wide major event days. Third, it checks that the Bureau of Meteorology declared that significant weather occurred on that day. If so, those days are excluded. If not, they remain in the data set and SA Power Networks removes the next worst day.

131 SA Power Networks submission to the Review Objectives and Process paper.

To effectively separate underlying performance in regions, an appropriate method should:

- exclude days when significant events occurred in a given region (ie localised severe weather, regardless of how it affected state-wide performance), and
- not inadvertently exclude days when there was no significant event affecting a given region.

Further, the method must be robust, replicable, and require a proportionate amount of effort.

The Commission will consider these factors in working with SA Power Networks to develop and consult publicly on an acceptable methodology for normalising regional performance data ahead of 1 July 2020. This method will be detailed in the revised Electricity Guideline No. 1.

6.3 Reporting on low reliability feeders

The final decision is that SA Power Networks will be required to identify low reliability feeders, with the definition amended so as to identify low reliability feeders in each region.

The definition of low reliability feeder will be amended to be: an individual feeder with USAIDI performance twice the mean USAIDI for that region for two consecutive financial years.[132]

Currently, a low reliability feeder is defined as an individual feeder with USAIDI performance approximately twice as high as the USAIDI target for that feeder class for two consecutive financial years.

The elements of performance reported for each low reliability feeder will continue to be:

- USAIDI and USAIFI performance as at 30 June;
- normalised USAIDI and USAIFI as at 30 June;
- geographic location of the feeder; and
- action already undertaken and/or any planned future action to improve the reliability of each identified feeder.

This change will have the effect of identifying each region's low reliability feeders, rather than each feeder category's low reliability feeders. Overall, more feeders will be identified. In 2017-18, the current approach identified 71 low reliability feeders, and the approach in this final decision would have identified 85.[133] This is summarised in Table 8.

Table 8: Total number of low reliability feeders, using the current approach, and the approach in this final decision

Definition	2015-16	2016-17	2017-18
Current definition: low reliability feeders are those with USAIDI performance approximately twice as high as the USAIDI target for that **feeder class**, for at least two consecutive financial years	70	90	71
Final decision: low reliability feeders are those with USAIDI performance approximately twice the mean USAIDI for that **region**, for at least two consecutive financial years	84	108	85

132 Essential Services Commission of South Australia, *SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period Final Decision*, pp. 39-40.

133 These feeders are identified using feeder level data provided by SA Power Networks, which was normalised using the Institute of Electrical and Electronics Engineers method.

The current approach of identifying each feeder category's low reliability feeders means they are concentrated in some regions – particularly the Eyre Peninsula.

Defining each region's low reliability feeders will result in there being fewer low reliability feeders identified in the Eyre Peninsula and the Eastern Hills. This is summarised in Table 9. Despite fewer feeders being classified as low reliability, the enhanced reporting regime will ensure clear, detailed and timely information is available about these regions as a whole.

Table 9: Comparison of the number of low reliability feeders in each region using the current approach and the approach in this final decision, 2017-18

Region	Low reliability feeders – current approach	Low reliability feeders – final decision approach	Difference
Adelaide Metropolitan Area	6	6	0
Barossa, Mid-North and Yorke Peninsula	4	16	12
Eyre Peninsula	28	17	-11
Fleurieu Peninsula	4	8	4
Eastern Hills	8	5	-3
Riverland and Murraylands	1	9	8
MRCs	1	2	1
South East	5	9	4
Upper North	14	13	-1
Total	71	85	14

6.3.1 Submissions to draft decision

One reason why SA Power Networks argues against introduction of regional reliability standards is the change to the definition of low reliability feeders. SA Power Networks' concern is not with the practicality of identifying low reliability feeders using the revised definition. The process of doing so is similar for each.

Rather, its concern is that the lowest reliability feeders in each feeder-type category will no longer be identified and reported. SA Power Networks notes that, for example, '26 feeders on the Eyre Peninsula that are consistently on the poorly performing feeder list will no longer be classified as poorly performing because of adopting region-based reliability standards.'[134]

The Business SA submission also advises that care be taken with low reliability feeder customers, given that the final decision both proposes not to make specific reliability standards for that customer group, and to reduce the value of duration payments (of which, historically, 37 percent have been made to low reliability feeder customers). This matter is addressed further in sections 4.1.1 and 4.1.2.

[134] SA Power Networks submission to Review draft decision.

6.3.2 Rationale

Reporting on low reliability feeders is particularly important because this final decision does not include separate network reliability standards or targets for customers who experience reliability that is far below average. Monitoring low reliability feeders allows for identification of customers not benefiting from (or receiving performance consistent with) average reliability standards and targets for an extended period of time.

Adjusting the definition to identify each region's low reliability feeders is consistent with other enhancements to the reporting regime that focus on regions.

This reporting will be complemented by the requirement of the AER's final Distribution Reliability Measures Guideline for new reporting on low reliability customers, in response to the fact that the STPIS only rewards average performance.[135]

6.4 SA Power Networks will report directly to its customers

> The final decision is that SA Power Networks will report directly to its customers on matters currently captured in performance reporting.

This will include all data and matters set out in Electricity Guideline No. 1. The Commission expects, at a minimum, quarterly and annual reporting, and reports following significant performance events.

This is in addition to SA Power Networks publishing a MECS (see section 3.5), which will form the basis for reporting following performance target exceedances or significant performance events.

With SA Power Networks reporting directly to the public, the Commission will not invest any less effort in performance monitoring. It will continue to scrutinise the performance of SA Power Networks, and redirect effort from preparing reports to auditing, data assurance and analysis. Reports published by SA Power Networks will also be made available through the Commission's website.

6.4.1 Submissions to draft decision

All submissions to the draft decision that specifically address the matter of SA Power Networks reporting directly to its customers are supportive.

SA Power Networks supports direct public reporting to improve transparency. SACOSS and Business SA each support improved accountability to customers, and the Energy Security for South Australia Working Party supports introduction of regular reporting.

Both the SA Power Networks and SACOSS submissions discuss how changed reporting obligations may affect costs. SA Power Networks' concerns relate to increased costs because of the number of regions for which monitoring and reporting will be required, and the extent of variation in regional performance. SACOSS do not support changes to reporting obligations if additional costs will result, and consider that SA Power Networks' existing internal reporting systems and processes must be sufficient to comply.

SACOSS specifically address the Commission's ongoing scrutiny of SA Power Networks, and ask that links to reports published by SA Power Networks also be made available through the Commission's website.

Business SA, the Energy Security for South Australia Working Party and SACOSS each support the proposed level of reporting by SA Power Networks. In particular, Business SA are strongly supportive of measures to improve transparency and increase SA Power Networks' accountability.

[135] The Australian Energy Regulator will define low reliability customers as those with greater than four times network average USAIDI (on a three-year rolling basis).

6.4.2 Rationale

Direct public reporting will improve accountability of SA Power Networks to its customers. This change will also encourage reporting to be integrated with SA Power Networks' ongoing customer communications and engagement program.

As mentioned in section 6.1.2, the Commission considers that the data and analysis required to satisfy the new reporting framework is the same data and analysis that SA Power Networks prepares regularly. It is required for SA Power Networks' day-to-day business. Reporting directly to the public should not result in additional effort or costs.

6.5 Annual regional reports

The final decision is that SA Power Networks will be required to publish annual reports for each region.

Reports will be prepared for each of the regions, in a manner that is accessible for customers. These may include description of performance as experienced by customers (ie without the exclusion of transmission and generation failures), performance with those exclusions, alongside underlying performance (ie excluding MEDs).

These may compare performance with average historical performance, and briefly explain departures from that performance. Detail may include: description of significant weather events and their impact; description of major outages; summary of outage causes; or, description of repair, replacement or augmentation activities in the region.

Regional reports would include a description of performance in relevant MRCs. For example, the Eyre Peninsula report would describe performance of Port Lincoln and Whyalla, although performance of those feeders is included in the Major Regional Centres regional category. It would also describe performance of the Eyre Peninsula's low reliability feeders.

6.5.1 Submissions to draft decision

Submissions were supportive of direct public reporting, and the introduction of regional reports, albeit with some concern about cost which has already been addressed.

Two submissions specifically address the need for detailed information about regional performance. The Energy Security for South Australia Working Party supports the compilation of regional reports, rather than detailed regional reporting being limited to explanations after major events.

Business SA stresses the importance of having granular data available for specific regions. It particularly notes the importance of this type of information being made available for the Eastern Hills, given its economic significance, and asked for such analysis to be included in this final decision. Business SA also considers that the performance of each regional town in the MRC category should be visible, if SA Power Networks fails to meet the overall target.

6.5.2 Rationale

The rationale for regional reports is the same as that for direct public reporting generally: it will improve accountability of SA Power Networks to its customers, and will encourage reporting to be integrated with SA Power Networks' communications and engagement program. Regional reports will be improve the accessibility of reporting, in that customers can easily find information about the region they live or work in.

The Commission has examined the following granular data for each region, as requested by Business SA:

1. Performance in each of the ten regions from 2005-06 until 2017-18. This analysis compares normalised and non-normalised performance with against the long-term average.
2. Performance of individual feeders within each region from 2005-06 until 2017-18. This analysis highlights the experience of customers that receive performance that is far from the mean.

Data prepared on this basis may be suitable for inclusion in ongoing reports. Some adjustments are required before it can be published. These include settling the method for normalising regional performance data, and revising feeders included in each region to align with those presented in Table 7.[136]

6.6 SA Power Networks must publish time-series data

The final decision is that SA Power Networks will be required to publish time-series data that is consistent with the overall revised framework.

SA Power Networks will be required to publish time-series data based on the Commission's decision on reliability standards for 2020 – 2025.

Whereas currently the Commission publishes a time-series dataset on its website, from 1 July 2020 SA Power Networks will be required to publish this information directly.

This will provide the basis for comparison against historical performance. SA Power Networks will be accountable for maintaining the accuracy, consistency and completeness of the data set. No submissions to the draft decision specifically address this matter.

[136] Specifically, Adelaide Business Area performance data must be updated to reflect the new boundary. Major Regional Centre data must be updated to include feeders in Crafers-Bridgewater, Mount Gambier, Murray Bridge, Port Pirie and Victor Harbor. It is currently based on feeders in Mount Barker, Port Augusta, Port Lincoln and Whyalla (those in the current Major Metropolitan Area Code reporting region). This adjustment will impact surrounding regions. Adelaide Metropolitan Area data must be updated to include agreed feeders in Gawler, which will have an impact on the adjacent Barossa, Mid-North and Yorke Peninsula region.

7 Next steps

The Commission will now work with SA Power Networks to settle the basis for the regional reporting regime. This work will include agreeing which feeders will be included in each region, and identifying the method for normalising regional performance data.

The Commission will publish data on regional performance before the start of the new regulatory period. This will include:

1. Performance in each of the ten regions from 2005-06 until 2017-18, comparing normalised and non-normalised performance with the trend.

2. Performance of individual feeders within each region from 2005-06 until 2017-18, highlighting how the reliability experienced by customers varies around the mean.

The final network performance targets will be established once data for 2018-19 are available, with final targets set in late 2019. The matter of whether performance targets will be set as the average of five or ten years' performance will be settled at that time.

Public consultation will occur on the consequential amendments to relevant regulatory instruments, namely the Code, and Electricity Guideline No. 1.

Appendix 1: Network reliability performance since 1999

The Commission is required to impose minimum standards of service that are at least equivalent to the levels that existed during the year prior to 11 October 1999. According to the Electricity Act section 23(1)(n)(v), the distribution licence issued by the Commission to SA Power Networks must require:

> '... the electricity entity to comply with code provisions as in force from time to time (which the Commission must make under the Essential Services Commission Act 2002*)* imposing minimum standards of service for customers that are at least equivalent to the actual levels of service for such customers prevailing during the year prior to commencement of this section and take into account relevant national benchmarks developed from time to time and requiring the entity to monitor and report on levels of compliance with those minimum standards'.

Commencement of this section was through the Electricity (Miscellaneous) Amendment Act 1999, proclaimed on 30 September 1999 with provisions taking affect from 11 October 1999.[137,138]

Due to issues with data quality, the Commission considers that the standards of service prevailing in 2005-06 proxy for the standards of service that existed during the year prior to 11 October 1999. The Commission routinely uses 2005-06 as the base year for analysing SA Power Networks' long-term reliability performance.

Levels of service prevailing in 2005-06 are set out in Table 10, for the whole network, each feeder-type category and each reporting region.

Table 10: Baseline performance data: standards of service prevailing in 2005-06

Region	USAIDI	Normalised USAIDI	USAIFI	Normalised USAIFI
Network-wide	200	185	1.95	1.83
Feeder-type categories				
CBD feeders	28	28	0.25	0.25
Urban feeders	160	147	1.72	1.66
Short rural feeders	208	187	2.19	2.01
Long rural feeders	358	335	2.52	2.42
Reporting regions				
Adelaide Business Area	28	28	0.25	0.25
Major Metropolitan Areas	161	148	1.72	1.66
Central Region	223	213	1.60	1.54
Eastern Hills and Fleurieu Peninsula	285	249	3.33	2.97
South East	206	206	2.12	2.12

137 Section 23 of the Electricity (Miscellaneous) Amendment Act 1999.
138 South Australian Government Gazette No. 139, 30 September 1999, p. 1341.

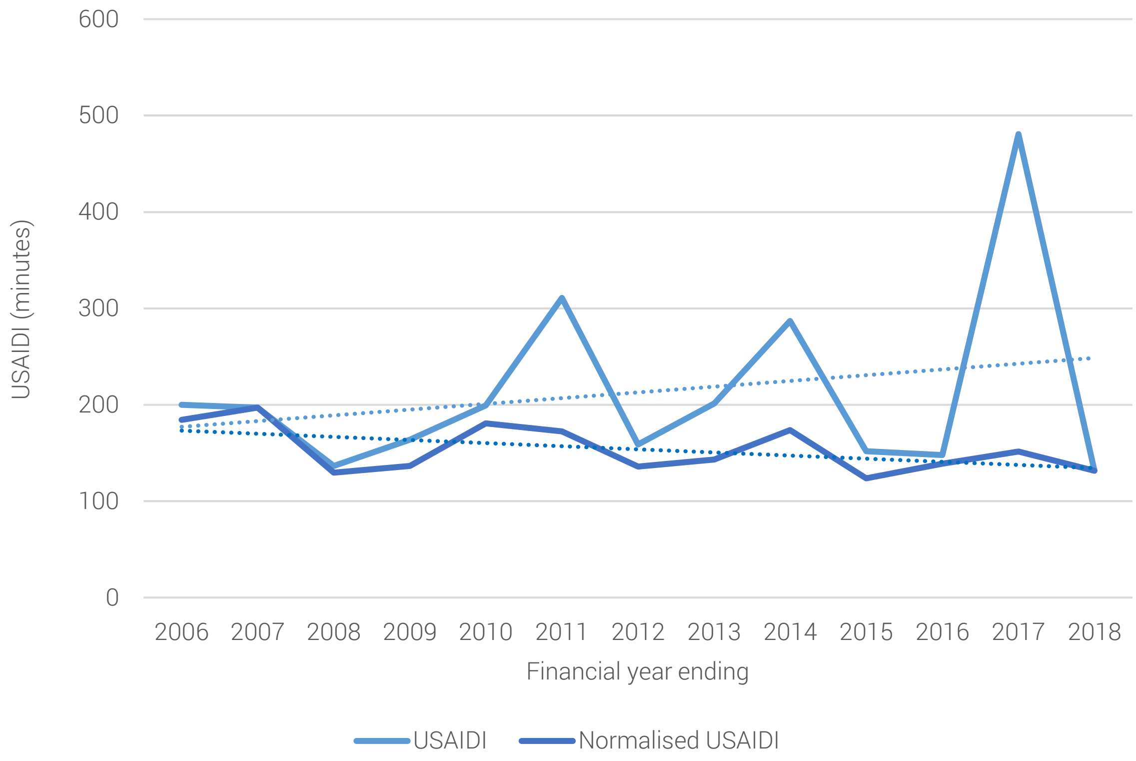
Region	USAIDI	Normalised USAIDI	USAIFI	Normalised USAIFI
Upper North and Eyre Peninsula	555	533	3.19	3.03
Kangaroo Island	1076	758	8.23	7.43

Source: SA Power Networks, data prepared for SA Power Networks Annual Reliability Performance Report for 2016-17.

Since 2005-06, network-wide normalised USAIDI, which excludes MEDs, has improved. The Commission has set network reliability standards for normalised performance since 2015. The Electricity Act provisions are not limited to normalised reliability.

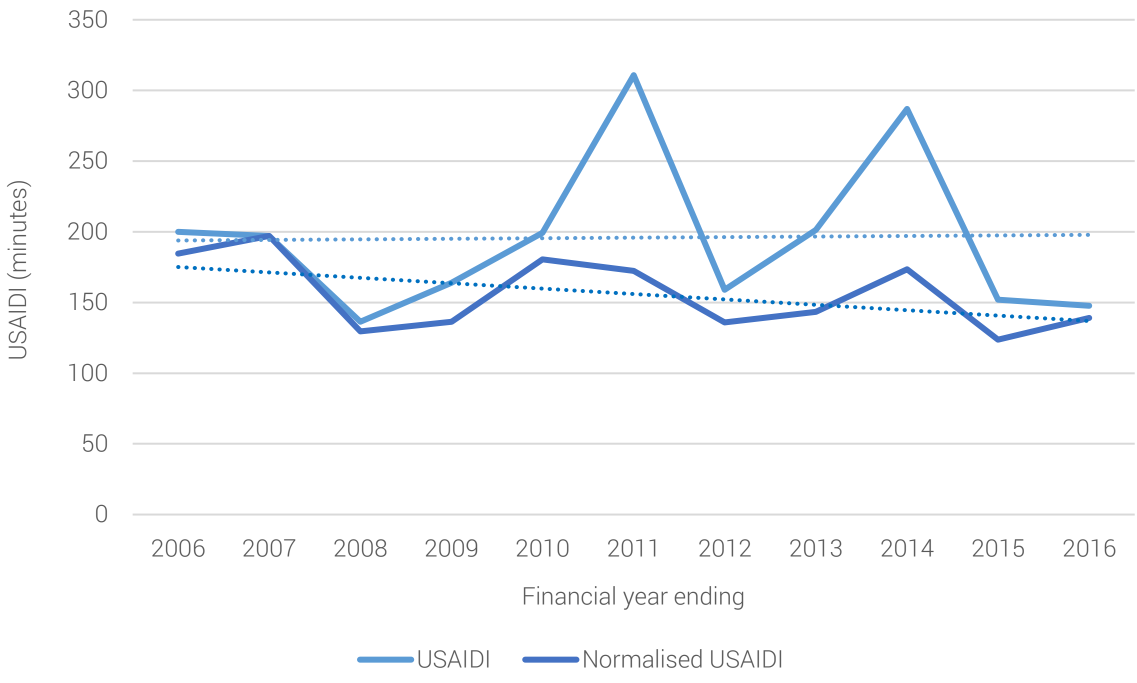
Non-normalised USAIDI exhibits high variability, most notably in 2016-17, a year with an unusual number of MEDs (see Figure 6). The trend, from 2005-06 until 2015-16 (ie excluding 2016-17), is that extremes in variability offset each other (see Figure 7). Trends in normalised and non-normalised USAIFI are shown in Figure 8.

Figure 6: Overall and normalised USAIDI performance since 2005-06 (with trend lines)



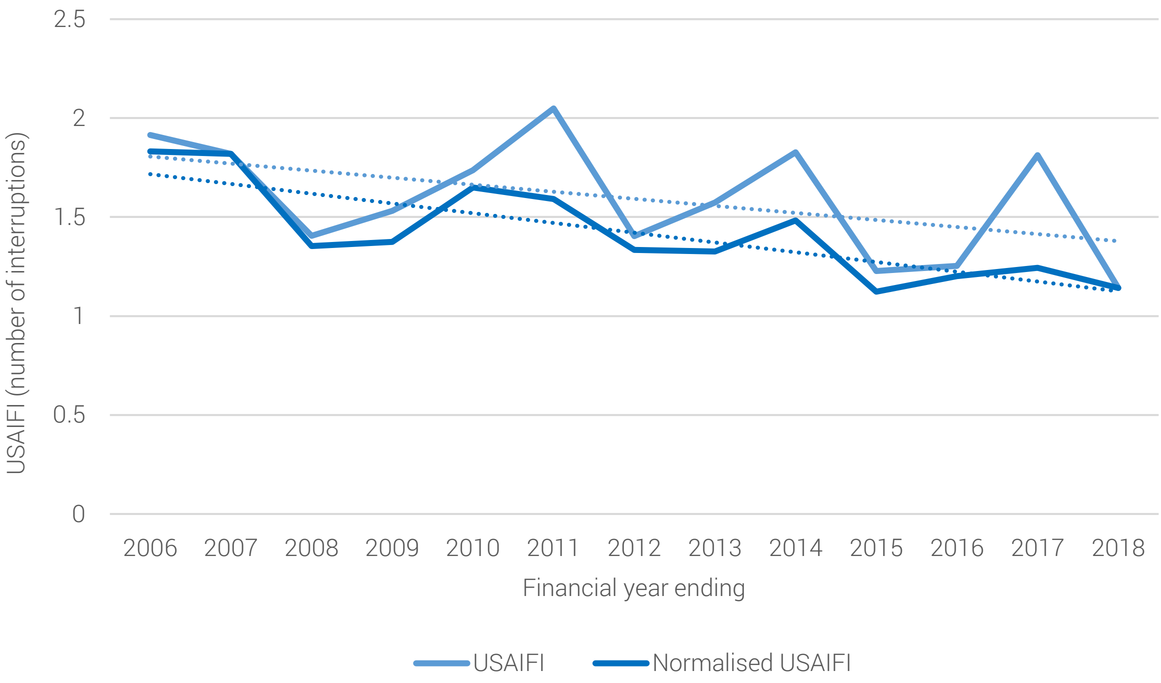
Source: SA Power Networks, Annual Performance Reporting to Commission.

Figure 7: Overall and normalised USAIDI performance since 2005-06, excluding 2016-17 and 2017-18 (with trend lines)



Source: SA Power Networks, Annual Performance Reporting to Commission.

Figure 8: Overall and normalised USAIFI performance since 2005-06 (with trend lines)



Source: SA Power Networks, Annual Performance Reporting to Commission.

Appendix 2: Cost-value scenarios

The cost-value scenarios are based on using capital expenditure to reduce mean interruption frequency on high voltage feeders.

Capital expenditure is that required to change mean USAIFI for each group, by either one, five or ten percent. For example, in Table 11, capital expenditure of $8.25 million is required to reduce (improve) average USAIFI for metropolitan customers from 1.35 by 0.01 to 1.34. This in turn impacts average USAIDI, by reducing (improving) it from 120 minutes to 119 minutes.

SA Power Networks maintains a database of costed capital expenditure projects. Inclusion of options based on using operating expenditure to improve reliability (for example, by increasing the number of depots and crews) was investigated. However, projects and costs held by SA Power Networks were not developed enough to provide a basis for, or to complement, scenarios based on capital expenditure.

The Commission requested that SA Power Networks identify the least cost solution for each level of reliability improvement. Therefore, the combination of capital expenditure projects used to achieve each scenario are different. Projects include:

- Vegetation: removing vegetation, covering overhead conductors, or undergrounding.
- Lightning: insulator upgrades and surge protection.
- Animal guards: installing animal guards.
- Reducing the number of customers interrupted by a fault: by installing mid-line reclosers, or through feeder automation.
- Reducing restoration times: by installing remote monitoring and control on switches, or using line fault indicators.

In metropolitan scenarios, the main projects used to deliver improvements are vegetation management, animal guards, feeder automation, and remote monitoring and control of switches. In non-metropolitan scenarios, the main projects used are insulator and surge protection upgrades, mid-line reclosers, switch upgrades, remote monitoring and control of switches and line fault indicators.

There is a high level of confidence in costs for some scenarios (for example, most of those based on one percent USAIFI improvements), where costs are drawn directly from SA Power Networks' costed capital expenditure database. There is a lower level of confidence in costs for other scenarios (for example, those based on five and ten percent USAIFI improvements), because project costs are unknown, but based on the costs for other, similar, projects.

As the actual costs are unknown, SA Power Networks provide an associated error margin (related to potentially higher costs). The confidence level (error margins) associated with the costs for each scenario are included in Table 11and Table 12.

The error margins have an important influence on projected costs. For example, an error margin of zero percent indicates a high level of certainty. The projected cost for a five percent improvement for low reliability feeders, with an error margin of zero percent, is $2.02 million. The cost range of a five percent improvement for non-metropolitan customers, with an error margin of + 50 percent, is $99.5 - $149.5 million. The cost range of a five percent improvement for metropolitan customers, with an error margin of + 100 percent, is $133.7 - $267.4 million.[139]

[139] These error margins apply to increasing costs only.

Table 11: Reliability scenarios for metropolitan, non-metropolitan customers, and low reliability feeder customers

Scenario		Metropolitan	Non-metropolitan	Low reliability feeders
Customers		624,851	261,689	27,084
Electricity consumption (MWh, 2016-17)		6,940,449	2,777,118	166,235
Mean performance (five years 2010 - 2015)	USAIDI	120	275	313
	USAIFI	1.35	2.40	2.81
1% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.01	0.02	0.03
	USAIDI	1.1	3.0	14.9
	Cost ($M)	8.25	10.57	2.02
	Error margin	0%	0%	0%
5% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.07	0.12	0.14
	USAIDI	4.9	21.3	47.2
	Cost ($M)	133.7	99.5	10.1
	Error margin	100%	50%	0%
10% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.14	0.24	0.28
	USAIDI	9.6	49.5	93.0
	Cost ($M)	368.9	281.3	30.3
	Error margin	200%	100%	100%

Notes:

1. Metropolitan areas includes metropolitan Adelaide, and some feeders in Port Lincoln, Whyalla, Port Augusta, Mount Gambier and Port Pirie. It does not include the Adelaide CBD.
2. Low reliability feeders are spread across metropolitan and non-metropolitan areas. They are not excluded from the metropolitan and non-metropolitan groups.
3. SA Power Networks provided error margins as escalation rules (ie multipliers to apply to actual costs). For example, where 0-25 percent of project cost was based on actuals, a further 200 percent was added to produce the estimated cost.
4. Values used for the contingent valuation survey and VCR analysis differ very slightly. SA Power Networks first provided this information in March 2018. This was used for the contingent valuation survey. It provided updated estimates in May 2018. These were used for the VCR analysis.
5. The total number of customers represented across metropolitan and non-metropolitan areas (excluding the CBD) is 886,500. This is based on the number of meters (National Meter Identifiers) active over a year, and is slightly more than the number of meters active at any one point in time.

Table 12: Reliability scenarios disaggregated by region

Scenario		Barossa, Mid-North, Yorke Peninsula	Eyre Peninsula	Fleurieu Peninsula	Adelaide Metropolitan Area	Eastern Hills	Riverlands and Murraylands	Rural Metropolitan Centres	South East	Upper North
Customers		57,724	15,969	45,309	583,352	37,210	48,162	41,499	32,252	25,063
Electricity consumption (MWh, 2016-17)		596,040	113,502	270,762	6,513,311	382,839	650,238	427,138	424,197	339,539
Mean performance (five years 2010 - 2015)	USAIDI	200	425	200	115	350	185	85	235	300
	USAIFI	1.50	1.85	1.65	1.25	2.55	1.35	0.85	1.75	1.35
1% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.02	0.02	0.02	0.01	0.03	0.01	0.01	0.02	0.01
	USAIDI	3.3	6.8	5.1	1.0	9.8	6.0	3.8	4.3	3.4
	Cost ($M)	1.74	0.65	2.24	6.07	3.13	1.81	2.57	0.11	0.76
	Error margin	0%	0%	100%	0%	0%	10%	0%	0%	0%
5% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.08	0.09	0.08	0.06	0.13	0.07	0.04	0.09	0.07
	USAIDI	12.8	36.7	25.4	4.4	26.7	26.2	6.8	19.7	24.1
	Cost ($M)	7.81	4.85	15.68	117.99	14.36	16.67	4.54	8.20	6.57
	Error margin	5%	5%	200%	100%	0%	100%	0%	100%	5%
10% improvement in USAIFI, and associated improvement in USAIDI	USAIFI	0.15	0.19	0.17	0.13	0.26	0.14	0.09	0.18	0.14
	USAIDI	24.6	74.0	50.8	8.6	47.8	51.4	10.4	38.9	50.0
	Cost ($M)	18.65	12.34	32.47	327.83	35.43	44.54	8.23	23.36	20.41
	Error margin	50%	50%	200%	200%	50%	200%	50%	200%	100%

Notes:

1. Adelaide Metropolitan Area does not include the CBD.
2. Rural Metropolitan Centres based on feeders in Port Lincoln, Whyalla, Port Augusta, Mount Gambier and Port Pirie.
3. SA Power Networks provided error margins as escalation rules (ie multipliers to apply to actual costs). For example, where 0-25 percent of project cost was based on actuals, a further 200 percent was added to produce the estimated cost.
4. Values used for the contingent valuation survey and VCR analysis differ very slightly. SA Power Networks first provided this information in March 2018. This was used for the contingent valuation survey. It provided updated estimates in May 2018. These were used for the VCR analysis.
5. Note that the total of costs here (Table 12) and in Table 11 are different. Segmenting the network in different ways means different levels of investment are required to achieve reliability improvements. That is, making a fixed level of improvements for each region has a cost different to the same improvement for the three groups in Table 11.
6. The number of customers is based on the number of meters (National Meter Identifiers) active over a year, and is slightly more than the number of meters active at any one point in time.

Appendix 3: Economic assessment of cost-value scenarios

The Commission used two complementary methods for quantifying the benefits of each cost-value scenario: contingent valuation and desktop VCR analysis. Desktop analysis using VCR is widely used for decision-making in the electricity sector. However, it has limitations including:

- Those inherent in the methods and design originally applied by AEMO (a combination of contingent valuation and choice modelling), which include a wide confidence interval of +/- 30 percent.[140]
- Those acknowledged by AEMO in its application guide (including that VCRs should not be used to assess high impact or prolonged widespread outages).[141]
- A single value of customer reliability is an average. In reality, the value of reliability varies across customer groups (for example, business, industry, agriculture, residential), across locations, and across individual customers.
- Adjustments based on Consumer Price Index and economic structure do not account for any underlying changes in how customers value reliability that have occurred since 2013-14.[142]

The contingent valuation study commissioned for this Review addresses some of these weaknesses: it is a contemporary valuation, based on the preferences of South Australian customers; it puts forward improvement scenarios based on real projects; and provides insights into how willingness to pay varies across customer groups (including by showing the amount of customers not willing to pay anything at all for reliability improvements).

However, contingent valuation also has limitations including the possibility of starting point bias, its ability to capture how people prioritise options for expenditure, the difference between stated willingness to pay and how people might behave in a 'real' market, and the extent to which responses are influenced by income (ability to pay). The approach and results of each method are summarised below.

Contingent valuation analysis

The Commission engaged consultants Oakley Greenwood and Wallis Market Research to complete a cost-value assessment using contingent valuation to quantify the benefits of reliability improvements. A final project report was published alongside the draft decision.[143]

Why use contingent valuation?

Contingent valuation is an economic valuation technique for quantifying the value of non-market goods or services, such as reliability improvements, for input into economic assessment. It uses surveys to ask people how much they are willing to pay for a benefit. It has been used in the electricity industry to ask people about their willingness to pay for reliability improvements. For example, it was one technique used by AEMO to develop its VCRs.

In selecting the contingent valuation method, use of another non-market valuation technique, choice modelling, was considered. Choice modelling asks people about their preferences for different 'packages' of non-market goods or services, such as unplanned interruptions with different characteristics (duration or frequency, time of year, time of day). It uses survey responses to model the value of those goods or services.

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140 Australian Energy Market Operator, *Value of Customer Reliability Review Final Report*, September 2014, p. 3, available at http://www.aemo.com.au/-/media/Files/PDF/VCR-final-report--PDF-update-27-Nov-14.pdf.

141 Australian Energy Market Operator, *Value of Customer Reliability Application Guide Final Report*, December 2014, p. 29, available at http://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf.

142 The Australian Energy Market Operator recognises such an approach will likely result in step changes when survey results are updated, but does not recommend a model to limit this step change.

143 Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages*.

It has also been used in the electricity industry: AEMO combined choice modelling with contingent valuation to construct its VCRs.

Contingent valuation was selected for this project because:

- It was the most direct way to obtain value estimates, in absolute dollar terms, and construct demand curves for reliability improvements.
- The contingent valuation survey presented people with starting values based on real costs of making reliability improvements, and asked if they were willing to pay. If the amount based on the real cost was accepted, people were asked if they would pay a little more. If rejected, people were asked if they would pay a little less, and so on. This allowed demand curves to be constructed for each improvement scenario, which show the range of amounts people are willing to pay.
- The reliability improvement scenarios developed for this Review have limited 'dimensions': outage frequency (which has a known impact on outage duration), customer group (metropolitan, non-metropolitan or low reliability feeder), and duration GSL payments.
- It was possible to adapt the contingent valuation method to ascertain respondent's priorities for different options (ie the 'dimensions' set out in the above point), by adding a reconciliation section, where respondents were able to review and prioritise their answers.[144]

The rationale for using contingent valuation is further described in section 2.2.2 of the Oakley Greenwood Final Report.

As all customers share the cost of distribution services regardless of whether they benefit directly, the contingent valuation survey used in this Review asked customers about willingness to pay to improve their own reliability, and about willingness to subsidise improvements for customers in other areas. These responses were combined to quantify total willingness to pay.

How were costs presented to customers?

As noted above, the contingent valuation survey presented people with starting values based on real costs of making reliability improvements. A consideration in deciding how to present these costs to customers was whether to:

a) Present the **bill increase** that would be required to deliver that improvement (ie the cost smeared across all SA Power Networks customers). For example, $30 million expenditure for low reliability feeders smeared across all customers equates to an ongoing annual bill increase of $2 for a typical residential customer and, on average, $5 for a business customer. Or,

b) Present the **full costs** firstly to those customers who would benefit directly from improvements, and then, separately, to those who would be required to subsidise improvements.

   In this approach, $30 million expenditure for low reliability feeders smeared across low reliability feeder customers (27,000) equates to an ongoing annual cost of $55 for a typical residential customer and, on average, $110 for a business customer.

[144] There have been recent developments in using contingent valuation as an alternative to choice modelling by including a reconciliation section. A recent Australian study about creek rehabilitation provides an example. (See J. Bennett, J. Cheesman and K. Milenkovic, 'Prioritising environmental management investments using the contingent valuation method', *Journal of Environmental Economics and Policy*, 2017, vol. 1, pp. 1-12). The study examined creek rehabilitation funded through rates bills. It asked people about their willingness to pay for several activities, then summarised their responses. People were invited to alter the individual amounts in the context of their total budget. This allowed people to assess trade-offs within their overall willingness to pay, and so reassess their prioritisation of spending.

On the advice of Oakley Greenwood, option b) was selected.[145] For each reliability improvement scenario, full costs were presented firstly to customers who would benefit directly and then to those who would not. The rationale is that the starting point based on full costs is more likely to ascertain whether the cost of real alternatives is acceptable. This is further explained in the Oakley Greenwood Final Report (sections 2.4 and 3.4).

How were benefits presented to customers?

The cost-value scenarios are based on reducing interruption frequency (USAIFI) by one, five and 10 percent. Interruption frequency was chosen as the basis for the scenarios because it can be impacted directly and predictably by capital investment.

When interruption frequency (USAIFI) is reduced, interruption duration (USAIDI) also falls. In the contingent valuation survey, reliability benefits were presented to customers as reductions in average annual interruption duration (USAIDI).

In the survey, short statements on current reliability introduced each section. For example: 'On average, customers like you in metropolitan Adelaide and major regional centres experience one unplanned power outage and just under two hours without power each year.'

The survey then asked how much each customer would be willing to pay for improvements. For example: 'The Essential Services Commission could set standards to reduce the average length and number of unplanned outages. The standard could be changed to reduce the two-hour average length of time customers like you are without power by five minutes. Would you be willing to pay $10 more each year – about $2.50 on each quarterly bill – for that improvement?'.

Sample structure and confidence levels

The contingent valuation study was conducted in May 2018 and obtained responses from 1,313 customers (1000 residential and 313 business).

The sample was designed to provide valid results for: the State as a whole; metropolitan customers; non-metropolitan customers; and, low reliability feeder customers. Each of these segments was required to have a representative mix of residential and business customers.

The residential sample was representative in terms of income, age and gender. The business sample was representative in terms of business size (by annual electricity consumption).

Residential respondents were required to have full or partial responsibility for paying the household electricity bill; business respondents were asked if they were the person who 'is in the best position to make decisions regarding electricity bills and electricity supply.'

Achieved sample sizes, and associated confidence levels and margins of error are shown in Table 13. Full detail on the sample design is included in Appendix B of the accompanying Oakley Greenwood Final Report, and statistical reliability is addressed in Appendix D of that report.

[145] Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages*, p. 17.

Table 13: Statistical error bands of the achieved sample

Segment	Sample size	Assumed population size	Error band at 95 percent confidence level	Error band 90 percent confidence level
All residential	1,000	805,459	3.1%	2.6%
Residential – metro	504	550,594	4.4%	3.7%
Residential – non-metro	231	230,590	6.6%	5.5%
Residential – low reliability feeder	265	23,865	6.0%	5.0%
All business	313	108,575	5.6%	4.7%
Business – metro	160	54,257	7.7%	6.5%
Business – non-metro	85	31,099	10.6%	8.9%
Business – low reliability feeder	68	3,219	11.8%	9.9%

Source: Oakley Greenwood, *Economic Assessment of Electricity Distribution Reliability Standard Packages,* Appendix D.

Results

The results show only one reliability improvement scenario with a net benefit: an average 10 percent reduction in interruption frequency (associated with a 90 minute annual average reduction in outage duration) for the 27,000 customers on low reliability customers. This scenario has a net annual benefit of $1.9 million.

Results from all three 10 percent scenarios (for metropolitan customers, non-metropolitan customers, and low reliability feeder customers), as reported by Oakley Greenwood, are summarised below in Table 14. Benefits include the willingness to pay of customers who would benefit directly from reliability improvements (those on low reliability feeders), and the willingness of other customers to subsidise those improvements.

Table 14: Annual net benefit of reliability improvements based on an average 10 percent reduction in outage frequency

	Metropolitan customers	Non-metropolitan customers	Low reliability feeder customers
Benefit	$6,426,433	$8,506,401	$3,618,505
Cost	$19,953,578	$15,204,529	$1,655,154
Net Benefit (Cost)	($13,527,145)	($6,698,128)	$1,963,350

Note: 10 percent reductions in outage frequency are associated with 10 minute (metropolitan customers) 25 minute (non-metropolitan customers) and 90 minute (low reliability feeder customers) reductions in outage duration.

Results showed that not all customers are willing to pay for these improvements. Two-thirds of the 27,000 customers on low reliability feeders who would benefit directly from the improvements set out in Table 14 are not willing to pay anything at all for that improvement. This is consistent for both residential (62 percent) and business customers (66 percent).

Likewise, there are customers who would not benefit directly who do not want to subsidise improvements. Customers in metropolitan areas were not willing to subsidise improvements for low reliability feeder customers (54 percent of residential, and 52 percent of business), and nor did customers in non-metropolitan areas (38 percent of residential, and 52 percent of business).

Results from all three five percent scenarios (for metropolitan customers, non-metropolitan customers, and low reliability feeder customers), as reported by Oakley Greenwood, are summarised below in Table 15. None show a net benefit.

Table 15: Annual net benefit of reliability improvements based on an average five percent reduction in outage frequency

	Metropolitan customers	Non-metropolitan customers	Low reliability feeder customers
Benefit	$3,516,382	$4,779,454	$190,990
Cost	$7,231,752	$5,371,077	$562,536
Net Benefit (Cost)	($3,715,370)	($591,623)	($371,546)

Note: Five percent reductions in outage frequency are associated with five minute (metropolitan customers) 10 minute (non-metropolitan customers) and 45 minute (low reliability feeder customers) reductions in outage duration.

The contingent valuation study also quantified customer's willingness to pay for duration GSL payments. It found that 52 percent of customers are willing to pay for inconvenience payments, 42 percent are not willing to pay, and six percent do not know.

It found that, on average, customers want to pay less than they currently do for such a scheme. The survey explained this would 'mean the payments would be smaller, or fewer people would get them'.

In aggregate, customers are willing to pay $6.4 million per annum for duration GSL payments, described in the survey as 'inconvenience payments', for long outages (an average of $7 per year, per customer). This is less than customers currently pay, which is $10.1 million per year (an average of $12 per year, per customer), for the entire GSL scheme (97 percent of scheme costs are for duration payments). [146] A full demand curve is included in the Oakley Greenwood Final Report as Figure 15.

VCR analysis

The second method used to quantify the benefits of each reliability improvement scenario was to apply a VCR across the cost-value scenarios of $40,620 per megawatt hour (MWh) of unserved energy. The VCR was estimated using values published by AEMO in 2014.

AEMO VCR estimates

The values published by AEMO are based on results of customer surveys conducted in 2013-14.[147] These surveys sampled 3000 residential and business customers across Australia. A South Australian sub-sample was included. The main survey combined contingent valuation and choice modelling.

Contingent valuation was used to ask customers about their willingness to pay to avoid experiencing basic outages. This was used to establish a baseline VCR. Choice modelling was used to explore customer preferences for different outage types.

[146] Guaranteed Service Level scheme costs are included in SA Power Networks' operating expenditure allowance determined by the Australian Energy Regulator. The most recent operating expenditure allowance was set with reference to 2013-14 as a base year, in which GSL payments were $10.1 million. (See Australian Energy Regulator, *SA Power Networks Determination 2015-16 – 2019-20 Final Decision – Attachment 7 Operating Expenditure*, October 2015, p. 64).

[147] Australian Energy Market Operator, *Value of Customer Reliability Project Page.*

Customers were shown a range of outage scenarios, each with a set of attributes (for example, length of outage, frequency of outage, time of day, week and year), and a fixed compensation amount. Customers were asked to choose between scenarios. Responses were used to adjust the baseline VCR.

The result of the AEMO survey and subsequent analysis was a suite of VCR values. It includes an aggregate VCR for the entire national electricity market, aggregate VCRs for each State, residential VCRs for each State, and business VCRs for each sector. AEMO considered developing residential VCRs for urban and regional customers in each State, but sample sizes were insufficient for statistically robust results.

Estimates based on the AEMO values are widely used by the AER and Australian electricity network service providers, and for determining STPIS incentive rates. AEMO acknowledges the potential use of its VCR values in economic assessment to inform distribution network reliability standards.[148]

Estimated VCR

The estimated VCR used in this Review is based on AEMO's aggregate VCR for South Australia, of $38.09 per kilowatt hour ($38,090 per MWh).[149] This VCR was adjusted for inflation for the period March 2014 to September 2017. A Consumer Price Index of five percent was used, a rate extracted from Australian Bureau of Statistics dataset 6401.0.[150]

Further, the AEMO VCR value was adjusted to reflect change in the composition of the South Australian economy since 2014. This was achieved using the Australian Energy Statistics published by the Department of Environment and Energy, and the ABS Energy Accounts. Values for 2016-17 were estimated by extrapolating available data.

These adjustments to AEMO's aggregate VCR for South Australia ($38,090 per MWh) produced the estimated VCR used in this Review ($40,620 per MWh). The estimated VCR used in this Review is higher than the value used to derive the SA Power Networks STPIS rate ($38,566 per MWh for urban, short rural and long rural feeders), which though also based on the AEMO value, was only escalated to the March 2015 quarter.[151]

Cost-value assessment model

A cost-value model was used to assess the net benefit of each reliability improvement scenario. This was achieved by applying the estimated VCR ($40,620 per MWh) to the reductions in interruption duration (USAIDI) associated with each scenario.

The model calculated net reliability benefits on an annual basis, as total annual reliability benefits less the total annual cost of improvements to deliver those benefits:

$$Net\ Reliability\ Benefit_{annual} = Reliability\ Benefit_{annual} - Cost_{annual}$$

[148] Australian Energy Market Operator, *Value of Customer Reliability Application Guide Final Report*, p. 17.

[149] Australian Energy Market Operator, *Value of Customer Reliability Review Final Report*, p. 30.

[150] As per the method indicated in the Australian Energy Market Operator, *Value of Customer Reliability Application Guide Final Report*.

[151] The Value of Customer Reliability values used to derive the SA Power Networks Service Target Performance Incentive Scheme rates are: $44,856 per MWh (CBD feeders) and $38,566 per MWh (urban, short rural and long rural feeders).These are based on the Australian Energy Market Operator's 2014 values, escalated to the March 2015 quarter. (See: Australian Energy Regulator, *SA Power Networks Determination 2015 – 2020 Final Decision Attachment 11 – Service Target Performance Incentive Scheme*, p. 11-8).

Annual reliability benefits

The model calculated annual reliability benefits using the estimated VCR, avoided customer outage minutes (Min_s), and electricity consumption for the relevant network segment ($Consumption_{min}$):

$$Reliability\ Benefit_{annual} = (VCR) \times Min_s \times Consumption_{min}$$

Where:

VCR is the estimated value of customer reliability ($40,620 per MWh)

Min_s is the expected avoided customer outage minutes (avoided USAIDI) due to defined reliability improvements.

$Consumption_{min}$ is the estimated electricity consumption (MWh) per minute for the relevant network segment. This estimate was prepared by dividing annual electricity consumption as provided by SA Power Networks by the number of minutes in a year.

(Note that the product of Min_s and $Consumption_{min}$ gives the expected reduction in unserved energy).

Annual reliability costs

The model calculated annual costs as annual repayments of the capital expenditure over an assumed asset life, plus annual operating expenditure:

$$Cost_{annual} = Capex_{annualrepayment} + Opex_{annual}$$

Where:

$Opex_{annual}$ is applied as two percent of total capital expenditure.

$$\boldsymbol{Capex_{annualrepayment}} = \left(\frac{r}{1-(1+r)^{-n}}\right) Capex_{total}$$

Where:

r is an assumed discount rate (seven percent).

n is the assumed life cycle of the proposed capital expenditure (50 years).

$Capex_{total}$ is the total capital expenditure, as provided by SA Power Networks.

Sensitivity analysis

There is a +/- 30 percent confidence interval associated with benefits quantified using the AEMO VCR. The Commission's VCR analysis incorporated a sensitivity analysis to assess the impact of the confidence interval on ranking of reliability improvement scenarios.

Low (-30 percent), base and high (+30 percent) estimates of VCR were calculated for each scenario. The full range of benefits was tested against costs, to consider if the preferred option changes.

For the purposes of assessing the impact of the +/- 30 per cent VCR confidence interval, costs were considered constant. In practice, the confidence interval associated with costs provided by SA Power Networks varied from zero to 200 percent (as shown in Table 11 and Table 12 in Appendix 2). This was considered separately, after analysis using the cost-value assessment model.

Results: metropolitan, non-metropolitan and low reliability customers

The VCR analysis found a net benefit in only one reliability improvement scenario: a one percent improvement in USAIFI for low reliability feeder customers (see Table 16).

However, the sensitivity analysis showed that this positive net benefit is uncertain. It exists in two-thirds of cases representing variation in the +/- 30 percent confidence interval, meaning it is uncertain whether benefits offset costs.

Table 16 also shows there is no net benefit for one percent USAIFI reliability improvements for either metropolitan customers as a group, or non-metropolitan customers, as a group. The tables that follow show no net benefits for five or ten percent USAIFI reliability improvements.

Table 16: Net benefits of reliability improvement scenarios (one percent USAIFI)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Metropolitan	$590,021	$758,171	($168,150)
Non-metropolitan	$643,877	$980,074	($336,198)
Low reliability feeders	$191,423	$184,920	$6,504

Table 17: Net benefits of reliability improvement scenarios (five percent USAIFI)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Metropolitan	$2,628,274	$12,361,882	($9,733,608)
Non-metropolitan	$4,571,524	$9,199,755	($4,628,231)
Low reliability feeders	$606,388	$933,844	($327,457)

Table 18: Net benefits of reliability improvement scenarios (ten percent USAIFI)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Metropolitan	$5,149,272	$34,108,438	($28,959,166)
Non-metropolitan	$10,623,965	$26,008,956	($15,384,991)
Low reliability feeders	$1,194,789	$2,801,533	($1,606,744)

Results: ten regional categories

Results for a one percent reduction in outage frequency across the ten regional categories proposed in this draft decision are shown in Table 19.

Results show small net benefits for this level of improvement for three regions: Riverlands and Murraylands ($134,870), South East ($130,008) and Upper North ($19,707).

For the Upper North, net benefits only exist in two-thirds of cases representing variation across the +/- 30 percent confidence interval associated with benefits quantified using the AEMO VCR, meaning it is uncertain whether benefits offset the costs.

For the Riverlands and Murraylands and South East, net benefits exist in all cases representing variation in the +/- 30 percent confidence interval. It is important to note the 10 percent confidence interval associated with costs for improvements in the Riverlands and Murraylands (though not for the South East), as per Table 12 in Appendix 2, which in turn impacts the annual net benefit.

Results for five and ten percent reductions are not presented here in full, due to very limited net benefits. These are: at the five percent level, a net benefit exists only for the Upper North ($25,403), and in two-thirds of cases representing variation across the +/- 30 percent confidence interval associated with benefits quantified using the AEMO VCR. No net benefits exist at the ten percent level.

Table 19: Net benefits of reliability improvement scenarios (one percent, regional disaggregation)

Network segment	Annual benefit	Annual cost	Annual net benefit (cost)
Barossa, Mid-North and Yorke Peninsula	$152,910	$160,875	($7,964)
Eyre Peninsula	$59,922	$60,346	($424)
Fleurieu Peninsula	$106,720	$207,069	($100,349)
Adelaide Metropolitan Area	$508,440	$561,201	($52,760)
Eastern Hills	$288,585	$289,390	($806)
Riverlands and Murraylands	$ 302,358	$167,489	$134,870
Rural Metropolitan Centres	$126,309	$237,214	($110,904)
South East	$140,486	$10,477	$130,008
Upper North	$89,756	$70,050	$19,707

Appendix 4: Exclusions in the STPIS

Table 20: Exclusions set out in the Service Target Performance Incentive Scheme

Exclusion	Description
Transmission and generation failures	To adopt exclusion of transmission and generation failures as per items 3.3 (a) (2) – 3.3 (a) (6) of the Service Target Performance Incentive Scheme. These include excluding interruptions due to: ▶ load shedding due to a generation shortfall ▶ automatic load shedding due to operation of under frequency relays following the occurrence of a power system under-frequency condition ▶ load shedding at the direction of the Australian Energy Market Operator or a system operator ▶ load interruptions caused by a failure of the shared transmission network, and ▶ load interruptions caused by a failure of transmission connection assets except where interruptions were due to; (a) actions, or inactions, of the distributor that are inconsistent with good industry practice; or (b) inadequate planning of transmission connections and the distributor is responsible for transmission connection planning.
Electricity legislation	To adopt exclusion of emergencies as per item 3.3 (a) (7) of the Service Target Performance Incentive Scheme. These are load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a distributor.
Emergencies	To adopt exclusion of emergencies as per item 3.3 (a) (8) of the Service Target Performance Incentive Scheme. These are load interruptions caused by a direction from state or federal emergency services, provided that a fault in, or the operation of, the network did not cause, in whole or part, the event giving rise to the direction.
Momentary interruptions (less than three minutes)	To replace exclusion of interruptions less than one minute. The Service Target Performance Incentive Scheme defines a momentary interruption as an interruption to a distribution customer's electricity supply with a duration of three minutes or less, provided that the end of each momentary interruption is taken to be when electricity supply is restored for any duration.
Other exclusions	As set out in the notes on standard definitions in Appendix A, Table A1 of the Service Target Performance Incentive Scheme. These include the exclusion of unmetered street lighting supplies, except where a distributor can identify the unmetered supplies from its historical performance data.

Source: Australian Energy Regulator, *Service Target Performance Incentive Scheme*.

ESSENTIAL SERVICES COMMISSION OF SOUTH AUSTRALIA