ESSENTIAL SERVICES COMMISSION OF SOUTH AUSTRALIA

Electricity

# Electricity Distribution Code review

## Final Decision

June 2023

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The Essential Services Commission is a statutory authority established as an independent economic regulator and advisory body under the *Essential Services Commission Act 2002* (ESC Act).

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# Glossary of terms

| | |
|---|---|
| 2020 – 2025 period | SA Power Networks 2020 – 2025 regulatory control period |
| 2025 – 2030 period | SA Power Networks 2025 – 2030 regulatory control period |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| Augex | Augmentation expenditure |
| CBD | Central Business District |
| CSBA | Customer Service Benchmarking Australia |
| Code | Electricity Distribution Code EDC/13 |
| Commission | Essential Services Commission, established under the *Essential Services Commission Act 2002* |
| CSIS | Customer Service Incentive Scheme |
| DER | Distributed Energy Resources |
| DNSP | Distribution Network Service Provider |
| DRMG | Distribution Reliability Measures Guideline |
| Electricity Act | *Electricity Act 1996* |
| Electricity Industry Guideline No. 1 | Electricity Industry Guideline No. 1, Electricity Regulatory Information – Requirements – Distribution |
| Electricity Regulations | *Electricity (General) Regulations 2012* |
| ESC Act | *Essential Services Commission Act 2002* |
| EWOSA | Energy and Water Ombudsman of South Australia |
| Framework | Public Lighting Service Framework |
| GSL | Guaranteed Service Level |
| HILP events | High Impact Low Probability events |
| kVA | kilovolt-amperes |
| LED | Light Emitting Diode |
| LGA SA | Local Government Association of South Australia |

| | |
|---|---|
| MECS | Monitoring Evaluation and Compliance Strategy |
| MEDs | Major Event Days |
| MW | megawatts |
| MWh | megawatt hours |
| NECF | National Energy Customer Framework |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NERR | National Energy Retail Rules |
| OMS | Outage Management System |
| Opex | Operating expenditure |
| OTR | Office of the Technical Regulator |
| OTTER | Office of the Tasmanian Economic Regulator |
| PLWG | Public Lighting Working Group |
| PV | Photovoltaic |
| Repex | Replacement expenditure |
| Review | Electricity Distribution Code review |
| RIN | Regulatory Information Notice |
| SACOSS | South Australian Council of Social Service |
| SAPS | Stand-alone Power System |
| SCADA | Supervisory Control and Data Acquisition |
| SIR | SA Power Networks Service and Installation Rules |
| SRMTMP | Safety, Reliability and Maintenance Technical Management Plan |
| STPIS | Service Target Performance Incentive Scheme |
| TIR | Technical Installation Rules |
| USAIDIn | Unplanned System Average Interruption Duration Index, normalised |
| USAIFIn | Unplanned System Average Interruption Frequency Index, normalised |
| VAR | volt-ampere reactive |

| | |
|---|---|
| VPP | Virtual Power Plant |
| WALDOs | Widespread and Long Duration Outages |

# 1 Executive summary

The Essential Services Commission (**Commission**) has reviewed the Electricity Distribution Code EDC/13 (**Code**) and made a final decision on changes that will apply to the Code from 1 July 2025.

The Code sets out consumer protections (standards and requirements) that apply to the distribution of electricity to customers in South Australia. It currently includes customer service standards, network reliability standards, a Guaranteed Service Level (**GSL**) scheme and provisions for the connection of embedded generation.

The Code applies to the distribution network operated by SA Power Networks. The Code review (the **review**) has been timed to align with the SA Power Networks revenue determination process. The Australian Energy Regulator (**AER**) makes a revenue determination for SA Power Networks every five years, and the next regulatory control period is from 1 July 2025 – 30 June 2030.

This review has aimed to ensure the Code is focused on matters for which the Commission has primary responsibility, and on which there is a clear need for, and net benefits from, regulation.

This final decision addresses five main areas:

- the application of the Code
- minimum network reliability standards
- minimum customer service standards
- distributed energy resources, and
- obligations for the timely repair of street lights.

Specific changes are summarised below, and decision points and associated amendments are set out in Table 2 (where departures from the draft decision are shown in bold).

Two documents are published alongside this final decision: a revised version of the Code and an expert technical report on the review of the existing provisions for connection of embedded generation.

**Application of the Code**

The current Code notionally applies to the 'distributor' and to some embedded generators. This final decision formally limits its application to SA Power Networks.

The current Code defines 'distributor' as a holder of a licence to operate a distribution network under Part 3 of the *Electricity Act 1996* (**Electricity Act**). In practice, it only applies to one such entity, SA Power Networks, which as the operator of South Australia's major electricity distribution network, has the only distribution licence which specifies compliance with the Code. To reflect this, the final decision is that the Code will be amended to apply only to Distribution Network Service Providers (**DNSPs**) regulated by the AER in South Australia with 50,000 or more connections at any given time, that is, to SA Power Networks.

Other distribution licences, held by small-scale operators, contain conditions relating to consumer protections which are tailored to the nature of each operation. Customer protections that apply in small-scale distribution networks licenced by the Commission are covered by separate regulatory instruments.[1]

[1] See Essential Services Commission of South Australia, Small-scale energy networks consumer protection framework review, 2021

The current Code applies to embedded generators not required to be registered under the National Electricity Rules (NER).

The final decision is to amend the Code so it no longer applies to embedded generators. This reflects the final decision (explained further below) to remove all Code provisions that apply to embedded generators in order to avoid duplication or inconsistency with other national and State regulatory instruments.

**Minimum network reliability standards**

The Code establishes minimum network reliability standards for the average duration of unplanned interruptions, the average frequency of unplanned interruptions, and the proportion of customers that experience very long interruptions.

The standards require that SA Power Networks must use its best endeavours to achieve a series of performance targets. If a performance target is not met, but SA Power Networks has applied its best endeavours in pursuing the target, the standard is satisfied.

The final decision is to retain the performance targets and reporting thresholds in the Code to apply in the 2025 – 2030 period.

This is sufficient to:

- facilitate reliability outcomes that satisfy the Commission's legislative requirement to impose minimum standards of service equivalent to those that existed before the privatisation of distribution services in South Australia
- facilitate reliability outcomes that are consistent with those of other National Electricity Market (NEM) distributors, and
- meet consumer expectations that reliability is maintained while increases to the cost of distribution services are minimised.

*CBD feeders*

In making the final decision to retain performance targets for Central Business District (CBD) feeders, the Commission has considered that targets for CBD feeders facilitate better reliability than those for other parts of the network.

This is consistent with the reliability outcomes of other NEM distributors and reflects both the substantial economic impact of interruptions in the CBD, and stakeholder views that the CBD is important as a centre for government, services and commerce.

Stakeholders have expressed concerns about recent CBD reliability, with some performance targets not being met in recent years (although the minimum network reliability standards have been satisfied). SA Power Networks has advised that the condition of some underground cables in the CBD indicates that they are near the end of their expected lifespan, which will materially affect CBD reliability in coming years.

The Commission expects SA Power Networks to make sufficient investment to deliver minimum network performance standards for CBD feeders, and that the efficient expenditure required to do so will be included in SA Power Networks' regulatory proposal. The AER is responsible for determining the efficient expenditure SA Power Networks requires to satisfy its jurisdictional regulatory obligations.

SA Power Networks' Monitoring Evaluation and Compliance Strategy (MECS) sets out, ahead of time, how SA Power Networks will apply its best endeavours in pursuing its performance targets. The Commission will have regard to the MECS if a best endeavours assessment is required during the 2025

– 2030 period, and expects that progress on delivery of any CBD expenditure program provided for in the AER's distribution determination will form part of the MECS.

*Urban, rural short and rural long feeders*

In making the final decision to retain performance targets for urban, rural short and rural long feeders, the Commission has considered consumer expectations that increases to the cost of distribution services are minimised, alongside SA Power Networks' forecast step-changes in repair and replacement expenditure and augmentation expenditure for the 2025 – 2030 period.

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

*Regional reliability*

The final decision is to retain existing regional reporting requirements to apply in the 2025 – 2030 period, and not establish minimum network standards for regions. The Commission uses regular reporting to maintain oversight of regional reliability.

In general, regional customers continue to experience lower levels of reliability than those in the metropolitan area. Although consumers remain generally satisfied with regional reliability, in SA Power Networks' early engagement on its regulatory proposal, some stakeholders indicated concern about changes in regional reliability and pockets of below-average performance.

Regional reporting will continue to be required for the 2025 – 2030 period. This remains important in order to monitor changes over time. To date, that reporting has shown that, while in some regions there have been recent individual years of performance worse than the historical average, there is no evidence of decline in long-term regional reliability for any particular region.

SA Power Networks is planning new expenditure to maintain long-term reliability in some regions: the Eyre and Fleurieu Peninsulas, the South East and the Upper North. SA Power Networks' early engagement on its regulatory proposal has revealed some support for that expenditure.

While the Commission will not establish any regional minimum network standards for the 2025 – 2030 period, it will consider establishing standards for specific regions if and when there is strong evidence of sustained decline. This approach has been used previously to drive improvements on Kangaroo Island during the 2010 – 2015 period.

*Stand-alone power systems*

Under recent changes to the NER, SA Power Networks may consider using Stand-alone Power Systems (SAPS) as an option to upgrade parts of its network. These changes do not affect existing SAPS that are not part of the NEM, such as small-scale distributors licensed by the Commission.

The review has considered how minimum network reliability standards need to apply in relation to distributor-led SAPS.

The final decision is that minimum network reliability standards will not be set for SAPS, because these are provided for by the national regulatory framework. The NER require SA Power Networks to develop, publish and comply with SAPS performance and supply standards before converting any customer to SAPS supply. The SAPS performance and supply standards must provide for SAPS customers to have reliability of supply that is no worse than if they were served by the interconnected network.

Although the Commission will not set minimum network reliability standards for SAPS, the final decision is that SAPS feeders must be included in regional reliability reporting. Further, once a SAPS feeder has been established for two years, it must be considered in identification of and reporting on low-reliability feeders. The Commission's Electricity Industry Guideline No. 1 – Electricity Regulatory Information Requirements Distribution[2] (**Electricity Industry Guideline No. 1**) will be updated to include this requirement.

GSL payments for the connection of new supply addresses and the duration and frequency of interruptions will apply to all distribution customers, including those on SAPS feeders. This is important to ensure that all distribution customers have equivalent customer protections.

*Network planning requirements*

The Code's current minimum network reliability standards do not prescribe how SA Power Networks should plan its network. Instead, the Code requires SA Power Networks to manage reliability outcomes, by applying its best endeavours to achieve performance targets and to manage its performance on Major Event Days (**MEDs**).

This means that SA Power Networks has responsibility for assessing the risk and uncertainty associated with managing its performance. This includes responsibility for anticipating and planning for High-Impact Low Probability (**HILP**) events. In assessing any expenditure proposal, the AER is required to consider this jurisdictional regulatory obligation.

SA Power Networks currently delivers network reliability outcomes through the application of its network planning criteria. In its submissions to this review, SA Power Networks proposed that the Commission formalise that approach by introducing a simplified version of those current network planning criteria into the Code.

The final decision is that no network planning requirements for supply reliability will be introduced to the Code at this time. The Commission supports the use of economic analysis in network planning to establish the value to customers of network investment (that is, a probabilistic approach to network planning) rather than only relying on a fixed, deterministic approach.

However, network planning decisions also need to be informed by analysis of costs and benefits that cannot be readily quantified, and by analysis of risk and uncertainty. Evidence suggests that the AER will take this type of flexible probabilistic approach in assessing forecast capital expenditure. [3]

The Commission will monitor how the AER assesses capital expenditure proposals which are not supported by a strictly probabilistic approach to network planning in its 2025 – 2030 distribution determination and revisit the matter of whether to include network planning requirements for supply reliability in the Code ahead of the 2030 – 2035 period.

*Minimum customer service standards*

The Code includes minimum customer service standards for responsiveness to telephone and written enquiries. If a performance target is not met, but SA Power Networks has applied its best endeavours in pursuing the target, the standard is satisfied.

The final decision is to add two new minimum customer service standards to the Code for the 2025 – 2030 period. These will relate to telephone responsiveness and first call resolution and apply specifically to calls to the General Enquiries line and Builders and Contractors line.

SA Power Networks' engagement has shown that, in relation to calls to these lines, resolving enquiries in the first instance is important to customer satisfaction, and that a slight increase in call wait times

[2] Essential Services Commission of South Australia, Electricity Industry Guideline No. 1, Electricity Regulatory Information – Requirements – Distribution, Version G1/13.1

[3] Confirmed in discussions with the Australian Energy Regulator, see also Australian Energy Regulator 2022, Network resilience – note on key issues, pp. 11-12

would be tolerated. The cost of providing first call resolution can be offset by allowing slightly longer wait times.

SA Power Networks has been measuring rates of first call resolution since January 2022. Before the start of the 2025 – 2030 period, the Commission will engage with SA Power Networks on its protocols for measuring first call resolution and establish performance targets. Performance targets will be based on historical performance. They will be published for consultation in January 2025 and finalised before the revised Code commences in July 2025.

The existing service standard for telephone responsiveness will remain but apply only to SA Power Networks' other telephone lines (most significantly, the Faults and Emergencies line). There, timely response is important to customer satisfaction and SA Power Networks' approach to responding to those calls is well-established and effective.

The service standard for written enquiry responsiveness will remain unchanged.

Together, these service standards will provide a baseline for SA Power Networks' customer service outcomes. The Commission will continue to require monitoring and reporting on customer satisfaction with communication quality. Additional customer service measures may be suitable for inclusion as parameters in the AER's Customer Service Incentive Scheme (**CSIS**).[4]

**Distributed energy resources**

Use of distributed energy resources (**DER**) continues to grow in South Australia, and is fundamentally changing the operating environment for SA Power Networks' distribution system.

DER contribute to the diversification and decarbonisation of the State's energy supply. Many customers with DER benefit directly by reducing electricity imports from the distribution network and by exporting and selling excess electricity. The NER now recognise exports from DER as one of the core services that distributors provide to customers.

National and State regulatory frameworks are evolving in response to the interaction of DER with the distribution network.

*Removing duplication and inconsistency*

The review has focused on removing duplication and inconsistency with other national and State regulatory instruments from the Code's provisions for the connection of embedded generation. These provisions relate to the connections process, financial charges, and technical matters.

The Code's provisions for the connection process and associated financial charges are now covered in the national framework, and the final decision is to remove those redundant clauses.

Many of the Code's technical requirements for connection are also duplicated either directly or in intent by requirements in the broader national and State regulatory framework.

In particular, many of the clauses are replicated, with more detail and specificity, in SA Power Networks' 2022 Service and Installation Rules (**SIR**) and associated Technical Standards. In changes to the SIR made in May 2022, the suite of Technical Standards for embedded generation became enforceable

[4] Since July 2020, the Australian Energy Regulator has provided for distributors to propose a Customer Service Incentive Scheme, as an alternative to the customer service component of the Service Target Performance Incentive Scheme. Distributors can propose measures to be included in the Customer Service Incentive Scheme, which must satisfy guidance principles set out by the Australian Energy Regulator and be supported by customers.[4] See Australian Energy Regulator, Customer Service Incentive Scheme explanatory statement and scheme design, 2019

under the *Electricity (General) Regulations 2012* (**Electricity Regulations**). The final decision is to remove duplicated clauses from the Code.

There are three clauses that are not duplicated by other regulatory provisions. These relate to the impact of embedded generation on the capacity of the distribution network to supply electricity (clause 3.10.1.b), delivery performance requirements (clause 3.13) and managing interference (clause 3.17). The final decision is that these will also be removed from the Code. The Commission will recommend to the Technical Regulator that it considers whether these matters should be provided for in regulatory instruments that it administers (noting that the current Electricity Regulations expire in September 2023).

*Other areas of risk to consumers*

The review has considered the Commission's role in managing consumer risks posed by the interaction of DER with the distribution network. Analysis presented in the Issues Paper found that most of the risks are being, or will be, addressed elsewhere in the national or State regulatory frameworks.

This final decision considers two specific risks raised in SA Power Networks' submission to the Issues Paper. These are risks arising from the operation of Virtual Power Plants (**VPPs**), and risks arising from the lack of continuity around connection agreements when the ownership of embedded generating units change.

*Other areas of risk to consumers – operation of VPPs*

Risks arising from the operation of VPPs include their potential impact on security, reliability, and quality of supply within the distribution network, and the potential impact on customers when VPPs control equipment on their behalf.

Permanent provisions to address these risks are expected to be made in the broader regulatory framework as a result of two other reviews: the Department for Energy and Mining's Review of the South Australian Electricity Licensing Framework, and the AER's Review of Consumer Protections for Future Energy Services. Both are due to conclude before the new Code commences.

Therefore, the final decision is not to introduce Code provisions to manage the risks to consumers associated with VPPs operating within the distribution network. The Commission will monitor the progress of the Department for Energy and Mining and AER reviews and consider if their outcomes adequately address any risks posed to SA consumers by VPPs.

*Other areas of risk to consumers – continuity of connection agreements*

Connection agreements are used to manage the potential impact of embedded generators on security, reliability, and quality of supply within the distribution network. All embedded generators have a connection agreement in place at the time of initial connection.

The National Energy Retail Rules (**NERR**) provide that deemed standard connection contracts apply to customers with embedded generation after a change of ownership. Embedded generators required to register with the Australian Energy Market Operator (**AEMO**) must maintain a connection agreement with SA Power Networks if ownership changes.

The full range of terms and conditions SA Power Networks uses in its initial connection of embedded generation cannot be imposed through deemed standard connection contracts. The Commission considers that inclusion of further technical conditions (which may be achieved by adding requirements to jurisdictional energy law) is a matter best addressed by the Technical Regulator.

There is a small group of generators for which there is no requirement or provision for a connection agreement to apply if ownership changes. These are embedded generators that are not customers and are not required to register with AEMO. SA Power Networks has indicated there are up to 50 such generators, including those with installations such as photovoltaic (**PV**) farms.

Ultimately, this gap may be addressed through changes to the national connections framework. It may alternatively be considered by the Department for Energy and Mining (**DEM**) in its Review of the South Australian Electricity Licensing Framework.

The final decision is that this gap will not be addressed through changes to the Code. The risks presented by this gap are low and manageable. Safety and technical requirements imposed under the Electricity Regulations apply to the ongoing operation of electrical installations.

Based on information provided by SA Power Networks, this gap may be managed using the current practice of approaching generators in this group to enter into connection agreements as they come to its attention. Further, SA Power Networks may, in consultation with the AER, consider if new connection agreements made with generators in this group may include a condition to require notification of any upcoming change in ownership or control.

### Obligations for the timely repair of street lights

SA Power Networks is responsible for operating around 240,000 street lights in South Australia for 69 public lighting customers, including local councils and the South Australian Department for Infrastructure and Transport. The Code has two provisions that apply to SA Power Networks' street light operations.

The first is a street light repair service standard, which requires SA Power Networks to use its best endeavours to repair street light faults affecting lights for which it is responsible within five business days in metropolitan Adelaide and some regional towns, and within 10 business days elsewhere.

The final decision is to remove the street light repair service standard. The service standard is no longer required, because a street light repair service level is included in the Public Lighting Service Framework (the **framework**), which is a product of negotiation between SA Power Networks and public lighting customers. The broader regulatory framework, in which the AER has a role, provides a structure for SA Power Networks to deliver and be held accountable for timely street light repairs.

The Code provides for a street light repair GSL payment. SA Power Networks must make a GSL payment to the first person to report the street light fault if it does not repair the fault within the five and 10 business day timeframes. A payment of $25 applies for each subsequent five- or 10-day period in which the fault is not repaired.

The final decision is to remove the street light repair GSL payment from the Code. The Commission has reviewed the cost of the payment, and the benefits attributed to it over time.

The payment has limited benefit. At best, it provides an uncertain incentive for people to report street light outages. The incentive is uncertain in that 94 percent of street light outages are resolved within the required timeframes, meaning that only six percent of people who report a street light outage receive a payment. Further, a case study (of the TasNetworks' experience) shows cessation of a street light GSL payment did not have a significant impact on the number of faults being reported.

As evidence suggests the payment provides an uncertain incentive, the risk is that there will be fewer reports of street light outages if it is removed is low. In the case that there are fewer reports made, SA Power Networks will need to develop a solution to obtain information about street light outages, in order to meet its obligation to repair street light faults within timeframes established by the framework.

As a transitional measure, annual reporting on street light outages and repairs will be retained during the 2025 – 2030 period to monitor the impact of these changes.

The final street light performance annual reporting requirements have a broader scope than established in the draft decision. This responds to concerns raised in consultation about SA Power Networks' operational reporting to public lighting customers.

The final decision includes a new Code obligation for SA Power Networks to report directly to its public lighting customers. Reporting content requirements will also be set out in Electricity Industry Guideline No. 1 and be subject to further consultation.

**Next steps**

The Commission would be pleased to meet with stakeholders to discuss this final decision.

Key dates for the remainder of the review are set out in Table 1 below.

The Commission will continue to monitor national and State reviews and regulatory reform regarding distributed energy resources and whether their outcomes adequately project the long-term interests of South Australian consumers.

Table 1: Key dates for remainder of review

| Date | Milestone |
|---|---|
| June 2024 | Targeted consultation on transitional street light performance reporting requirements |
| January 2025 | Public consultation on draft amendments to Electricity Industry Guideline No. 1<br><br>Public consultation on performance targets for new telephone responsiveness and first call resolution service standards |
| April 2025 | Publication of final Electricity Industry Guideline No. 1 (G1/14) |
| 1 July 2025 | Commencement of revised Electricity Distribution Code (EDC/14) |

Table 2: At a glance - summary of main decision points (departures from draft decision are shown in bold)

| Issue number | Topic and reference to full discussion | Current arrangement | Final decision on arrangement for 2025 - 2030 | Final decision on amendments to Code |
|---|---|---|---|---|
| 1 | Application of the Code (section 3) | The Code applies to:<br><br>the distributor, defined as a holder of a licence to operate a distribution network under Part 3 of the Electricity Act, and<br><br>embedded generators not required to be registered under the NER.<br><br>SA Power Networks has the only distribution licence that requires compliance with the Code. Consumer protections for small-scale operators apply as tailored licence conditions. | The Code will apply only to DNSPs regulated by the AER in South Australia with 50,000 or more connections at any given time. This narrows application of the Code to one distributor, SA Power Networks, which is already the case in practice.<br><br>**In this final decision, the definition of 'distributor' refers to DNSPs regulated by the AER in South Australia with '50,000 or more connections' at any given time, rather than '10,000 or more domestic customers'.**<br><br>The Code will no longer apply to embedded generators. This is no longer necessary given the proposal to remove the Code's existing provisions for the connection of embedded generators (see section 5.1). | **Definition of 'distributor' amended**<br><br>References to 'SA Power Networks' replaced with references to 'the distributor'<br><br>Definition' of 'SA Power Networks' removed<br><br>Clauses 1.2.1(b) and 3.1.1 removed |
| 2 | Minimum network performance targets (section 4.1) | Minimum network reliability targets and thresholds, and minimum network restoration targets set at the previous review using 10 years of historical performance data.<br><br>Definition of low-reliability feeder references the same 10-year period. | Network reliability targets and reporting thresholds (clause 2.2.1) and network restoration targets and reporting thresholds (clause 2.2.2) will not be changed in the next version of the Code.<br><br>This will maintain reliability outcomes that satisfy legislative requirements, are consistent with other NEM distributors, and meet consumer expectations that reliability is maintained with minimal cost impact.<br><br>The Commission's current definition of low-reliability feeder will also be retained, but moved to Electricity Industry Guideline No. 1. | No amendments<br><br>Minor edits for clarity in clauses 2.2.1 and 2.2.2<br><br>Definition of low-reliability feeder moved to Electricity Industry Guideline No. 1 |

| Issue number | Topic and reference to full discussion | Current arrangement | Final decision on arrangement for 2025 - 2030 | Final decision on amendments to Code |
|---|---|---|---|---|
| 3 | Regional reliability (section 4.2) | Reporting on regional reliability | Regional reporting requirements will continue to apply in the 2025 – 2030 period.<br><br>No regional minimum network reliability standards will be established for the 2025 – 2030 period. The Commission will consider the need for targeted improvements in specific regions if and when there is strong evidence of sustained decline. | No amendments |
| 4 | Stand-alone power systems (section 4.2) | - | The Code will not set minimum network reliability standards for SAPS feeders. These are provided in the national regulatory framework.<br><br>SAPS feeders will be included in regional reliability reporting and, once a SAPS feeder has been established for two years, it must be considered in identification of and reporting on low-reliability feeders.<br><br>GSL payments for the connection of new supply addresses and the duration and frequency of interruptions will apply to all distribution customers, including those on SAPS feeders. | Definitions of 'feeder' and 'interruption' amended<br><br>Definitions of 'SAPS feeder' and 'Regulated SAPS' added<br><br>Clause 2.3.1(c)(i)(A) amended |
| 5 | Network planning requirements (section 4.4) | No network planning requirements for supply reliability | No network planning requirements for supply reliability will be introduced to the Code at this time.<br><br>The Commission will meet with the AER as it makes its distribution determination to understand how it assesses proposals which are not supported by a strictly probabilistic approach to network planning. | No amendments |

| Issue number | Topic and reference to full discussion | Current arrangement | Final decision on arrangement for 2025 - 2030 | Final decision on amendments to Code |
|---|---|---|---|---|
| 6 | Minimum customer service standards (section 4.5) | Minimum customer service standards apply to responsiveness to telephone and written enquiries. | Two new minimum service standards will be added to the Code:<br>1) telephone responsiveness for calls to the General Enquiries line and the Builders and Contractors line, and<br>2) first call resolution for calls to the General Enquiries line and the Builders and Contractors line.<br>Performance targets will be published for consultation in January 2025.<br>The existing service standard for telephone responsiveness will remain but apply only to other SA Power Networks telephone lines (most significantly, the Faults and Emergencies line). The service standard for written enquiry responsiveness will remain unchanged.<br>Additional customer service measures may be suitable for inclusion as parameters in the AER's CSIS. | Clause 2.1.1 amended. |
| 7 | Existing provisions for connection of embedded generation (section 5.1) | Provisions for the connection process and associated financial charges (clauses 3.2 – 3.8) and technical requirements for connection (3.9 – 3.17). | Clauses which relate to the connection process and associated financial charges will be removed because they are addressed in the NER.<br>Clauses which relate to technical aspects of the connection of embedded generators that are now addressed by other regulatory provisions or are otherwise no longer necessary will be removed.<br>The three clauses that are not addressed by other regulatory provisions will also be removed from the Code. The Commission will recommend to the Technical Regulator that it considers whether these matters should be provided for in the broader State framework. | Clauses 3.2 to 3.17 removed<br>Definitions of 'Australian Standard', 'electricity distribution determination', 'embedded generation unit', 'embedded generator', 'good electricity industry practice', 'large embedded generator', and 'small embedded generator' no longer used, removed |

| Issue number | Topic and reference to full discussion | Current arrangement | Final decision on arrangement for 2025 - 2030 | Final decision on amendments to Code |
|---|---|---|---|---|
| 8 | Risks posed by Virtual Power Plants (section 5.2.1) | - | The Commission will not introduce Code provisions to manage the risks to consumers associated with VPPs operating within the distribution network.<br><br>These risks include potential impacts on security, reliability, and quality of supply, and risks to customers when VPPs control equipment on their behalf.<br><br>The requirement for provisions to address these risks will be considered by reviews being conducted by the DEM and the AER. | No amendments |
| 9 | Connection agreements for embedded generators (section 5.2.2) | - | The Commission will not introduce Code provisions that affect the terms and conditions that may be included in deemed standard connection contracts. The matter of which technical provisions should apply to the connection and operation of embedded generation in South Australia is one for the Technical Regulator.<br><br>The Commission will not introduce Code provisions that require continuity of connection agreements for the small group of generators for whom this is not already required by the national framework. This gap poses a low risk that can be managed by other means. | No amendments |
| 10 | Street light repair service standard (section 6.1) | SA Power Networks must use its best endeavours to repair street light faults affecting lights for which it is responsible within five business days in metropolitan Adelaide and some regional towns, and within ten business days elsewhere. | The street light repair service standard is no longer required, the Public Lighting Service Framework contains a street light repair service level and provides a structure for SA Power Networks to deliver and be held accountable for timely street light repairs. | Clause 2.3.1(b)(i) and the definition of 'street light fault' removed |

| Issue number | Topic and reference to full discussion | Current arrangement | Final decision on arrangement for 2025 - 2030 | Final decision on amendments to Code |
|---|---|---|---|---|
| 11 | Street light repair GSL payment (section 6.2) | SA Power Networks must make a GSL payment to the first person to report the street light fault if it does not repair the fault within defined timeframes. | The street light repair GSL payment will be removed, on the basis that its benefit is limited to being an uncertain incentive for people to report street light outages. The risk that there will be fewer reports after it is removed is low and manageable.<br><br>Annual reporting on street light outages and repairs will be retained during the 2020 – 2025 period. | Clause 2.3.1(b)(ii) removed |
| 12 | Street light repair performance reporting (section 6.3) | SA Power Networks must report to the Commission on metrics set out in Electricity Industry Guideline No. 1. | SA Power Networks must report to the Commission and directly to its public lighting customers on street light performance. Reporting requirements will be set out in Electricity Industry Guideline No. 1 and be subject to further consultation.<br><br>This will promote accountability of SA Power Networks to its public lighting customers and ensure oversight by the Commission of the timely repair of street light faults. | Clause 2.7.6 and definition of 'public lighting customer' added |

# 2 Introduction

This final decision explains the changes to the Electricity Distribution Code (EDC/13) (**Code**) that will apply from 1 July 2025.

The Code sets out consumer protections (standards and requirements) that apply to the distribution of electricity to customers in South Australia. In practice, the Code applies only to the distribution network operated by SA Power Networks. It includes customer service standards, network reliability standards, a Guaranteed Service Level (**GSL**) scheme and provisions for the connection of embedded generation (see Box 1). The Code complements the consumer protections established in the National Energy Customer Framework (**NECF**).

SA Power Networks operates South Australia's major electricity distribution network, which connects over 915,000 customers to the National Electricity Market (**NEM**). SA Power Networks' distribution network links the transmission network, which supplies electricity from larger generators, with customers. The distribution network also supports a large and growing amount of distributed energy resources (**DER**), including rooftop photovoltaic (**PV**) solar panels, connected directly to the distribution network. Energy exports from DER are now recognised as one of the core services distributors provide to customers.[5]

The Code review (the **review**) has assessed the effectiveness of the Code and changes required. The last review of the Code was conducted between 2018 and 2020.[6] There is no mandated timeframe for this review. However, it is timed to align with the SA Power Networks distribution determination process. The Australian Energy Regulator (**AER**) makes a distribution determination for SA Power Networks every five years, and the next period is from 1 July 2025 – 30 June 2030.

**Box 1: What is currently in the Electricity Distribution Code?**

The Code sets out consumer protections (standards and requirements) that apply to the distribution of electricity to customers in South Australia. These include:

- Customer service standards, relating to responsiveness to telephone and written enquiries.
- Network service standards, including reliability standards for the average duration and frequency of unplanned interruptions, and restoration standards for the proportion of customers that experience very long interruptions.
- A Guaranteed Service Level scheme, which provides for payments to customers when service levels for the duration and frequency of supply interruptions, promptness of new connections and timeliness of street light repairs are not met.
- Monitoring, evaluation, and performance reporting provisions, which include requirements for reporting to the Commission and to the public.
- Embedded generation provisions that relate to the process, charges and technical standards for connection to the distribution network.

## 2.1 Review scope

The Code sets out jurisdictional requirements for electricity distribution services. Since the Code was first made, there have been progressive changes in the wider legislative and regulatory framework for

5 Australian Energy Market Commission, Access, pricing and incentive arrangements for DER, 2021. This change introduces some consumer protections for export services to the national framework.

6 Essential Services Commission of South Australia, SA Power Networks 2020 reliability standards review

electricity distribution services (see Box 2). There have also been market and technology changes and shifts in consumer behaviour and sentiment. These factors mean changes to the Code are necessary. At the same time, other issues have emerged, some unique to South Australia, which are best addressed through the Code.

The review has aimed to ensure the Code is focused on matters for which the Commission has primary responsibility, and on which there is a clear need for regulation.

Matters for which the Commission has primary responsibility include: those which are clearly defined in legislation, and matters which are important to the long-term interests of South Australian consumers with respect to price, quality and reliability of essential services, which are not dealt with elsewhere in the national or State regulatory instruments.

## 2.2 Review process

The Commission has relied on the following inputs in making this final decision:

- SA Power Networks' operational performance reporting to the Commission[7]
- submissions to the Issues Paper published in April 2022[8]
- submissions to the draft decision published in January 2023[9]
- direct consultation with stakeholders, including other regulators
- complaints data from the Energy and Water Ombudsman of South Australia (EWOSA)
- relevant national benchmarking
- the customer engagement program that SA Power Networks is conducting to inform development of its regulatory proposal,[10] and
- expert technical review of the existing provisions for connection of embedded generation.

## 2.3 Outline of final decision

This final decision addresses five main areas. These relate to: application of the Code, minimum network reliability standards, minimum customer service standards, distributed energy resources, and obligations for the timely repair of street lights.

Two documents are published alongside this final decision: a revised version of the Code (which includes revisions arising from this final decision and minor typographical amendments); and, an expert technical report on the review of the existing provisions for connection of embedded generation (which also accompanied the draft decision).

7 Information about SA Power Networks' regulatory performance is on the Commission's website at: ESCOSA - SA Power Networks' regulatory performance

8 Essential Services Commission of South Australia, Electricity Distribution Code review, 2022, Issues Paper and submissions

9 Essential Services Commission of South Australia, Electricity Distribution Code review, 2023, Draft Decision and submissions

10 That program has involved 'broad and diverse' engagement workshops and 'focused conversations' through 2022 and a 'people's panel' deliberative process in 2023. The SA Power Networks engagement approach and materials are available on the Talking Power website.


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The revised Code will take effect from 1 July 2025. The final decision will result in changes to SA Power Networks' regulatory reporting requirements, set out in Electricity Industry Guideline No. 1. The Commission will consult publicly on those changes before they are finalised in June 2025.

Box 2: The Code's Legal Framework

The Commission's powers to make, vary and amend industry codes or rules are provided by Part 4 of the *Essential Services Commission Act 2002* (**ESC Act**). The Commission is required to keep industry codes under review, though the frequency and timing of those reviews are not prescribed by legislation.

The Code exists within the broader national energy market framework that is established by the provisions of the Australian Energy Market Agreement. That framework incorporates the National Electricity Law, National Electricity Rules and the National Energy Customer Framework.

The Australian Energy Market Agreement defines the activities which form part of the national framework, and the activities which are retained by States and territories. Until 1 July 2010, economic regulation of distribution services was a State responsibility, administered by the Commission. Economic regulation of distribution services is now a national responsibility. The AER makes a revenue determination for SA Power Networks every five years. Over time, Code provisions have been removed or updated to reflect development of the national energy framework.

Many consumer protections for distribution customers are now contained within the National Energy Customer Framework. However, the Australian Energy Market Agreement provides for states to retain the function of setting service reliability standards. The *Electricity Act 1996* (**Electricity Act**) provides for that function to be administered by the Commission. Specifically, the Electricity Act establishes the requirement and power for the Commission to licence electricity distributors and requires that licence conditions must include compliance with industry code provisions that impose minimum standards of service (see section 23(n)(v)).

Other content in the Code exists either because of a specific legislative requirement (for example, the requirements for reconnection after disconnection at clause 2.4 satisfy a requirement of the National Energy Retail Rules, Schedule 2, 13.2), or because of a gap in the national or State energy regulatory framework.

The Electricity Act requires that the Commission must avoid duplication of, or inconsistency with, the national energy framework (section 6A(4)), and not impose licence conditions that duplicate or are inconsistent with either the Electricity Act or the national energy framework (section 24B).

In turn, the national framework stipulates that the AER must make revenue allowances that provide for jurisdictional requirements to be met. In relation to capital and operational expenditure to meet service standards, the relevant provisions are National Electricity Rules 6.5.6 (a)(2) and 6.5.7 (a)(2).

# 3 Application of the Code

The Electricity Distribution Code EDC/13 (**Code**) applies to the 'distributor', defined as a holder of a licence to operate a distribution network under Part 3 of the *Electricity Act 1996* (**Electricity Act**). SA Power Networks has the only distribution licence which specifies compliance with the Code. The Code also currently applies to embedded generators which are not required to be registered under the National Electricity Rules (**NER**).

## 3.1 Code will apply only to SA Power Networks

The final decision is to amend the Code so it applies only to Distribution Network Service Providers (**DNSPs**) regulated by the Australian Energy Regulator (**AER**) in South Australia with 50,000 or more connections at any given time. This clarifies that the Code operates alongside the national framework, as it already does in practice.

The Code currently applies to the 'distributor', defined as a holder of a licence to operate a distribution network under Part 3 of the Electricity Act. SA Power Networks has the only distribution licence which specifies compliance with the Code.

The final decision is to amend the Code so it applies only to Distribution Network Service Providers regulated by the Australian Energy Regulator in South Australia with 50,000 or more connections at any given time, that is, to SA Power Networks.[11]

The relevant amendment is to the definition of distributor, which has been changed in the revised Code. This narrows application of the Code to SA Power Networks, which affects the meaning of clause 1.2.

The new definition of distributor allows for references to 'SA Power Networks' to be replaced with references to the 'distributor'. The definition of 'SA Power Networks' is no longer required and is removed.

The new definition of distributor aligns the application of the Code with the application of the July 2023 Small-scale Electricity Networks Code.[12]

The Small-scale Electricity Networks Code sets out customer protections that apply in small-scale distribution networks licenced by the Commission. It applies to electricity distribution licensees with fewer than 50,000 connections (but not to those distribution networks where the licensee holds an exemption from the requirement to be a registered network service provider issued by the AER).[13] Customers of small-scale distributors need consumer protections that are commensurate with the risks presented by their distributor's operations. Risks presented in small-scale networks differ from those in SA Power Networks' distribution network, and vary depending on scale, location and technology.

The new definition of distributor responds to the possibility that in the future there may be additional small distributors regulated by the AER in South Australia (for example, new stand-alone networks). The revised definition makes it clear that Code provisions would not apply to those distributors.

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[11] Distribution Network Service Providers regulated by the Australian Energy Regulator in South Australia are listed here

[12] Essential Services Commission of South Australia, Small-scale energy networks consumer protection framework review

[13] Essential Services Commission of South Australia, Small-scale Electricity Networks Code, July 2023, clause 1.2.1(a)(ii)

In the draft decision, the proposed definition of 'distributor' was a DNSP regulated by the AER in South Australia with 10,000 or more domestic customers. The term 'domestic customer', and threshold of 10,000 customers was used to align with the definition of 'excluded networks' in the Electricity Act.[14]

In its submission to the draft decision, SA Power Networks expressed concern that the amended definition of 'distributor' introduced a new term, 'domestic customer' to the Code.[15] SA Power Networks also expressed concern about consistency between the Code and the National Energy Consumer Framework (NECF), which establishes consumer protections for all 'small customers'.[16]

The Commission acknowledges SA Power Networks' concern about introducing a new term to the Code, particularly as the term 'domestic customer' is not defined in the Electricity Act and only used there in relation to feed-in tariffs. The final decision is to not introduce this new term to the Code.

The definition has also been amended to so it relates to the number of connections at any given time, reflecting that the number of connections may fluctuate during the operation of the Code.

## 3.2 Code will not apply to embedded generators

The final decision is to amend the Code so it does not apply to embedded generators. This is no longer necessary given the proposal to remove the Code's existing provisions for the connection of embedded generators (discussed in section 5.1).

The final decision is to amend the Code so it does not apply to embedded generators.

There are two clauses in the current Code that define its application to embedded generators: clauses 1.2.1(b) and 3.1.1(b)(ii) – (iv). These clauses specify that the Code applies to embedded generators which are not required to be registered under the NER.

It is no longer necessary for the Code to apply to embedded generators, given the proposal is to remove all of the Code's existing provisions for the connection of embedded generators (as discussed in section 5.1).

The relevant amendments are the removal of clause 1.2.1(b) and clause 3.1, as shown in the revised Code published alongside this final decision.

14 In the Electricity Act, 'excluded network' means a distribution network that supplies electricity to less than 10,000 domestic customers for the purposes of the Division 3AB—Feed-in mechanisms.

15 SA Power Networks submission to Draft Decision, p. 4

16 'Small customers' are residential customers, and business customers with annual electricity consumption below 160 MWh. The National Energy Retail Law (South Australia) Act 2011 defines 'small customer' in section 5(2). There, a small customer is a customer who is a residential customer, or who is a business customer who consumes energy at business premises below the upper consumption threshold. As specified by the National Energy Retail Law (Local Provisions) 2013 section 5(2), the upper consumption threshold for determining whether business customers are small or large is160 MWh. These definitions are in turn consistent with the definition of 'small customer' in the Electricity Act 1996, which is a customer with an annual electricity consumption level less than the number of MWh per year specified by regulation for that purpose, or any customer classified by regulation as a small customer.

# 4 Minimum service standards

The Code establishes a number of minimum service standards which relate to network reliability and customer service. These standards require that SA Power Networks use its best endeavours[17] to achieve a series of targets for average annual performance in normal conditions.

Minimum network reliability standards relate to:

- the average duration of unplanned interruptions (measured as Unplanned System Average Interruption Duration Index normalised, **USAIDIn**) and the average frequency of unplanned interruptions (measured as Unplanned System Average Interruption Frequency Index normalised, **USAIFIn**) (at clause 2.2.1), and
- restoration standards to limit the proportion of customers who experience very long interruptions (at clause 2.2.2).

The minimum network reliability standards apply to four feeder categories: CBD feeders, urban feeders, rural short feeders and rural long feeders.

SA Power Networks' performance on Major Event Days (**MEDs**) is assessed separately.[18] MEDs are days of outlying reliability performance, typically due to extreme weather. Their impact is excluded for the purpose of performance targets. SA Power Networks' obligation in relation to MEDs is to apply its best endeavours in managing reliability outcomes.

The Commission does not set service standards for regions. However, SA Power Networks is required to report on regional network reliability, which provides oversight for the Commission and consumers. Reporting is required for ten regional categories that align with SA Power Networks' network planning regions.

In its regional reporting, SA Power Networks reports to the Commission and the public on average reliability outcomes (measured as USAIDIn and USAIFIn) and provides reasons for variation in performance. It also identifies and reports to the Commission low-reliability feeders within regions.

Minimum customer service standards relate to responsiveness to telephone calls and written enquiries (at clause 2.1). In addition, SA Power Networks is required to monitor and report on customer satisfaction with communication quality.

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[17] Best endeavours means to act in good faith and use all reasonable efforts, skill and resources. If a performance target is not met, but SA Power Networks has applied its best endeavours in pursuing the target, the reliability standard is satisfied.

[18] Since 2015, performance targets have been set for normalised performance, where Major Event Days (**MEDs**) are removed from performance data. MEDs are days of outlying reliability performance, as defined by the Institute of Electrical and Electronics Engineers IEEE Standard 1366-2012. There are typically three MEDs each year, usually due to extreme weather. There were five in the 2021-22 regulatory year. Normalising performance removes some, but not all, impact of events outside the control of the distributor.

## 4.1 Minimum network performance targets

> The final decision is to retain the minimum network performance targets in the current Code to apply in the 2025 – 2030 period.
>
> The network reliability targets and reporting thresholds (clause 2.2.1) and network restoration targets and reporting thresholds (clause 2.2.2) will not be changed in the next version of the Code. The Code's current definition of a low-reliability feeder, which references the same ten-year period used to set targets in the current Code, will be retained (but moved to Electricity Industry Guideline No. 1).
>
> This will satisfy the Commission's legislative responsibilities to establish standards that are at least equivalent to the level of service that existed before privatisation of distribution services in South Australia, and that maintain reliability outcomes that are consistent with those of other National Electricity Market (**NEM**) distributors. It will facilitate reliability outcomes that are consistent with consumer expectations that reliability is maintained while cost increases are minimised.

The final decision is to retain the minimum network performance targets in the current Code to apply in the 2025 – 2030 period. In making that decision, the Commission has analysed historical performance data, and considered both its legislative responsibilities and the cost of maintaining reliability outcomes. Each of these factors are explained below.

The final decision to retain targets in the current Code differs from historical decisions. At each historical decision, the Commission reset minimum network performance targets using an average of performance over the longest possible time period. For example, ten years of data were used to set targets for 2020 – 2025, extended from the five years of data used to set targets for 2015 – 2020. Further detail on this approach is included in Appendix 1.

### 4.1.1 Submissions to draft decision

In its submission to the draft decision, SA Power Networks supported the Commission's proposal to retain the minimum network performance targets in the current Code for CBD feeders.[19]

However, SA Power Networks disagreed with the Commission's proposal to retain the minimum network performance targets in the current Code for urban, rural short and rural long feeders. Instead, it advocated for resetting targets based on the most recent ten-year performance.

Its submission asserted that retaining the targets in the current Code would not align with its customers' preferences and would be 'contrary to preferences expressed by customers in our customer engagement as part of our 2025-30 reset process.' [20]

This contrasts with the view put forward by the South Australian Council of Social Service (**SACOSS**) in its submission to the draft decision. SACOSS indicated it did not support resetting the targets. It agreed with the Commission's proposal to retain the existing Code requirements. SACOSS considered that resetting the targets would drive further increases in costs to consumers which would not be acceptable in the context of the current energy affordability crisis.[21]

The Commission acknowledges these different perspectives. It was clear in SA Power Networks' engagement that consumers support reliability being maintained. The different perspectives in submissions relate to what it means to 'maintain' reliability.

[19] SA Power Networks submission to Draft Decision, covering letter
[20] SA Power Networks submission to Draft Decision, pp. 5-6
[21] South Australian Council of Social Service, submission to Draft Decision, p. 3

The final decision means that reliability outcomes facilitated by the Code will remain the same. There will be no change in jurisdictional regulatory obligations.

In recent years, SA Power Networks has (with a few exceptions) delivered reliability outcomes beyond those required by the Code. Consumers have expressed concern about the step-change in cost of maintaining reliability at that level.

The final decision balances consumer preferences for maintaining reliability and their concern about cost.

### 4.1.2 Analysis of historical performance data

Accurate, consistent historical network performance data is available for the 13 years from 2009-10 to 2021-22.

Across that period, average duration of interruption (USAIDIn) and frequency of interruption (USAIFIn) outcomes have been slightly better than the performance targets in the current Code for urban, rural short, and rural long feeders, and slightly worse than the performance targets in the current Code for CBD feeders. These differences are shown in Table 3 and Table 4 below.

Across that period, average restoration of supply outcomes have been slightly better than some performance targets in the Code for urban and rural short feeders. These differences are shown in Table 8 of Appendix 1.

Table 3: Duration of interruption (USAIDIn) targets in 2015 – 2020 and 2020 – 2025, and average performance over 13 years to 30 June 2022

| | **USAIDIn targets (minutes)** | | | |
|---|---|---|---|---|
| | CBD feeders | Urban feeders | Rural short feeders | Rural long feeders |
| **2015 - 2020 targets** based on average performance over five years to 30 June 2014 | 15 | 120 | 220 | 300 |
| **2020 - 2025 targets** based on average performance over ten years to 30 June 2019 | 15 | 110 | 200 | 290 |
| **Average performance over 13 years to 30 June 2022** | 18 | 104 | 189 | 287 |

Table 4: Frequency of interruption (USAIFIn) targets in 2015 – 2020 and 2020 – 2025, and average performance over 13 years to 30 June 2022

| | USAIFIn targets (interruptions) | | | |
|---|---|---|---|---|
| | CBD feeders | Urban feeders | Rural short feeders | Rural long feeders |
| **2015 - 2020 targets** based on average performance over five years to 30 June 2014 | 0.15 | 1.30 | 1.85 | 1.95 |
| **2020 - 2025 targets** based on average performance over ten years to 30 June 2019 | 0.15 | 1.15 | 1.65 | 1.75 |
| **Average performance over 13 years to 30 June 2022** | 0.15 | 1.09 | 1.50 | 1.66 |

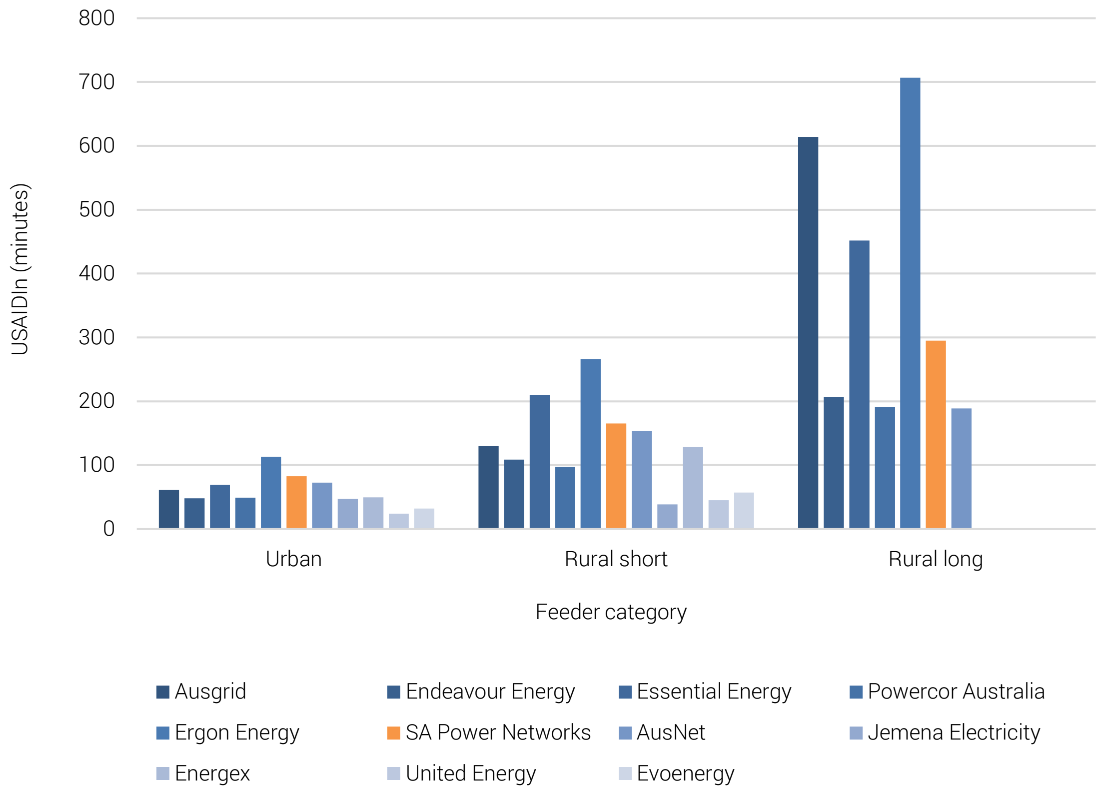
### 4.1.3 Legislative responsibilities

In establishing minimum network performance targets, the *Electricity Act 1996* (**Electricity Act**) requires the Commission to impose minimum standards of service equivalent to those that existed before the privatisation of distribution services in South Australia. The targets in the current Code satisfy this requirement. Further detail about that requirement is included in Appendix 1.

The Electricity Act also requires the Commission to take into account relevant national benchmarks in establishing minimum standards of service. The targets in the current Code facilitate reliability outcomes that are consistent with other NEM distributors.

Performance of urban, rural short and rural long feeders across NEM distributors is illustrated below in Figure 1. Performance of CBD feeders across NEM distributors is illustrated in Figure 2, and discussed further in section 4.1.5.

Figure 1: USAIDIn performance across NEM distributors, 2020-21




Data source: Annual reporting to the AER, Annual Reporting Regulatory Information Notices (**RINs**) Templates - 6.2 STPIS reliability. TasNetworks is excluded because it does not report by feeder category. Not all listed distributors have rural long feeders.

### 4.1.4 Managing the cost of maintaining network reliability

Broadly, consumers expect that network reliability is maintained and are hesitant about supporting changes that will increase costs.[22] Reliability is an important, but not sole, driver for repair and replacement expenditure (**repex**) and augmentation expenditure (**augex**). The Commission's minimum network performance standards will be one reference point for the AER's decision about the prudent and efficient level of capital expenditure to provide for in its distribution determination.[23]

To date, SA Power Networks has required minimal expenditure for the specific purpose of meeting minimum network reliability standards.

SA Power Networks has delivered reliability outcomes as a result of expenditure for other primary purposes, such as the design, technical, and safety standards brought together in annual Safety, Reliability and Maintenance Technical Management Plans (**SRMTMPs**). It has delivered improvements on the reliability outcomes provided for in each regulatory determination in response to the AER's Service Target Performance Incentive Scheme (**STPIS**).

[22] This matter was explored extensively at the last Code review (see: Essential Services Commission of South Australia, SA Power Networks reliability standards review – final decision, 2019 pp. 10-16)

[23] As required by National Electricity Rules 6.5.6 and 6.5.7

SA Power Networks is developing its regulatory proposal for the 2025 – 2030 period. To inform its proposal, SA Power Networks is conducting an extensive engagement process to understand the expectations and priorities of customers and other stakeholders.

SA Power Networks' engagement program involved 'broad and diverse' workshops and a series of 'focused conversations' in 2022, and a 'people's panel' deliberative process which concluded in March 2023. It will consult on a draft regulatory proposal in mid-2023 before making its submission to the AER in January 2024.

To inform the 'focused conversation' stage of its community engagement, SA Power Networks prepared scenarios on different reliability outcomes, and estimated the associated repex and augex. All scenarios were published on its Talking Power website.

The early repex and augex estimates presented during the 'focused conversations' provided an indication of the expenditure SA Power Networks may include in its regulatory proposal.[24] The estimates suggest that a step change in expenditure will be proposed for the 2025 – 2030 period, and that meeting minimum network reliability standards is an important driver of that change.[25]

SA Power Networks also uses operating expenditure (**opex**) to manage reliability outcomes. In its early engagement on its regulatory proposal, it has not indicated a step change in reliability opex.

SA Power Networks has indicated that the Commission's minimum network performance standards are one driver of these step changes in expenditure. Retaining targets in the current Code will keep that driver constant.

The Commission has considered and decided against the approach it has used at each historical Code review, of resetting targets using an average of performance over the longest possible time period (15 years' data will be available before the start of the 2025 – 2030 period). For urban, rural short and rural long feeders, that change would facilitate reliability outcomes that exceed consumer expectations, and may impact on cost and deliverability. For CBD feeders, that change may result in reliability outcomes that do not meet consumer expectations (as discussed further in the next section).

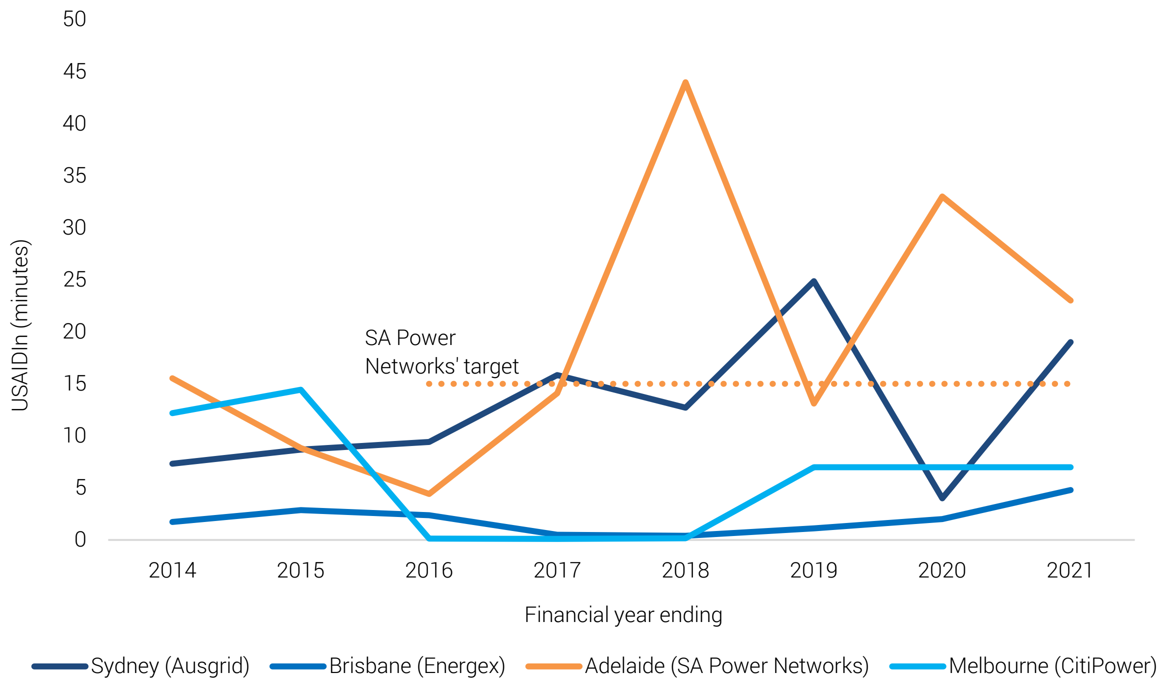
### 4.1.5 Performance of CBD feeders

The CBD feeder performance targets in the current Code are needed to facilitate reliability outcomes that are consistent with other NEM distributors. SA Power Networks' current CBD feeder USAIDIn performance target of 15 minutes is shown relative to the performance of NEM distributors in Figure 2.

24 See SA Power Networks, Focused conversation – managing a reliable, safe and resilient network – workshop two presentation and notes, 2022, slides 55-58, 62, 76, detail about Scenario 2, and SA Power Networks, Focused conversation –managing a reliable, safe and resilient network – workshop three presentation slide deck, 2022, slides 76-77, detail about Scenario 2.

25 See discussion in Essential Services Commission of South Australia, Electricity Distribution Code review – draft decision, January 2023, p. 23

Figure 2: CBD feeder USAIDIn performance, 2013-14 to 2021-22




Data source: For SA Power Networks, reporting to the Commission. For Ausgrid, Energex and CitiPower, reporting to the AER - Annual Reporting RINs, Templates - 6.2 STPIS reliability

In several recent years, SA Power Networks has not met some CBD feeder performance targets. For example, as shown in Figure 2, it did not meet the performance target for duration of interruptions (15 minutes USAIDIn) in 2017-18, 2019-20 or 2020-21. SA Power Networks' performance does not compare well with the performance of other NEM distributors.

Recent CBD performance has been affected by issues including faults on different types of underground cables (which are reaching the end of their useful life) and construction damage.[26]

Targets for the CBD require better reliability than targets for other parts of the network. This is consistent with the reliability outcomes of other NEM distributors and reflects both the substantial economic impact of interruptions in the CBD,[27] and stakeholder views that the CBD is important as a centre for government, services and commerce.

In engagement on its regulatory proposal, SA Power Networks presented evidence that the condition of some underground cables in the CBD will materially affect CBD reliability in coming years.[28] SA Power

[26] Information about SA Power Networks' historical performance outcomes for each regulatory year is available at: ESCOSA - SA Power Networks' regulatory performance, and in SA Power Networks' 2021 fact sheet Maintaining reliable and cost-effective electricity supply for Adelaide's CBD

[27] The economic impact of an additional unit of USAIDIn or USAIFIn is high for CBD feeders because individual CBD customers consume relatively large amounts of electricity, and because the value of reliability ($/MWh) is higher for CBD feeders than for urban, rural short and rural long feeders (due to a greater concentration of commercial customers). See: Australian Energy Regulator, Final decision – SA Power Networks 2020-25, Attachment 10: Service target performance incentive scheme, 2020, pp. 10-11 and Australian Energy Regulator, Value of customer reliability review: final decision, 2019

[28] See SA Power Networks, Focused conversation – CBD reliability—workshop two presentation, September 2022, slide 60; Essential Services Commission of South Australia, Electricity Distribution Code review – draft decision, January 2023, p. 24

Networks is updating its CBD reliability forecasts as it assembles further evidence about the condition of underground cables.[29]

SA Power Networks is developing a CBD asset replacement program for inclusion in its 2025 – 2030 regulatory proposal that is informed by its forecasts of CBD reliability. In its engagement, it provided an estimate of the works and expenditure needed to return CBD reliability to the targets in the current Code by the end of the 2025 – 2030 period.[30]

The estimate suggests that a step-change in CBD-related expenditure will be proposed for the 2025 – 2030 period, and that meeting minimum network reliability standards is an important driver of that change.[31] SA Power Networks will continue to update its cost estimates as it prepares its regulatory proposal.

The Commission expects that SA Power Networks will make sufficient investment to deliver minimum network performance standards for CBD feeders, and that the efficient expenditure required to do so will be included in SA Power Networks' regulatory proposal. The AER is responsible for determining the efficient expenditure SA Power Networks requires to satisfy its jurisdictional regulatory obligations.

SA Power Networks' Monitoring Evaluation and Compliance Strategy (**MECS**) sets out, ahead of time, how SA Power Networks will apply its best endeavours in pursuing its performance targets.[32] The Commission will have regard to the MECS if a best endeavours assessment is required during the 2025 – 2030 period, and expects that progress on delivery of any CBD expenditure program provided for in the AER's distribution determination (measured using indicators such as kilometres of cable replaced and number of feeders automated) would form part of the MECS.

If a case arises where minimum network performance standards are not satisfied, the Commission will consider regulatory intervention having regard to matters such as the statutory framework, relevant licence and code conditions, the circumstances of the event and the actions taken by SA Power Network (see the terms of the Commission's Enforcement Policy for further information).[33]

29 SA Power Networks has shared forecasts refined using updated modelling of asset condition with the Commission on a confidential basis.

30 SA Power Networks, CBD reliability – focused conversation – scenario summary, 2022, and SA Power Networks People's Panel – CBD reliability, 2022, pp. 7-8, detail about Scenario 2

31 SA Power Networks, CBD reliability – focused conversation – scenario summary, 2022, and SA Power Networks People's Panel – CBD reliability, 2022, pp. 7-8, detail about Scenario 2

32 The Code requires SA Power Networks is required to produce a Monitoring, Evaluation and Compliance Strategy which set outs, ahead of time, what application of its best endeavours entails, as per clause 2.6. See: SA Power Networks June 2022 MECS.

33 Essential Services Commission of South Australia, Enforcement Policy, version 2.6, August 2021, see in particular section five.

## 4.2 Regional reliability

> The final decision is to continue to require regional reporting for the 2025 – 2030 period. This provides the Commission and consumers oversight of regional reliability.
>
> No regional minimum network reliability standards will be established for the 2025 – 2030 period. However, the Commission will consider requiring targeted improvements for specific regions if and when there is strong evidence of sustained decline.
>
> The Commission's expectation remains that SA Power Networks will manage regional reliability within its overall distribution determination.

Approximately 70 percent of SA Power Networks' distribution network infrastructure by circuit length is outside major metropolitan areas. It serves 30 percent of customers.

In general, regional customers outside of major regional centres experience lower levels of reliability. This is because there is less interconnection and redundancy in the network, longer operational response times, and higher costs per customer to maintain assets.

In SA Power Networks' early engagement on its regulatory proposal, consumers and stakeholders have indicated concern about changes in regional reliability (around equity, vulnerability and public safety), and concern about pockets of below average performance within regions (particularly low-reliability feeders).

### 4.2.1 Regional reliability reporting

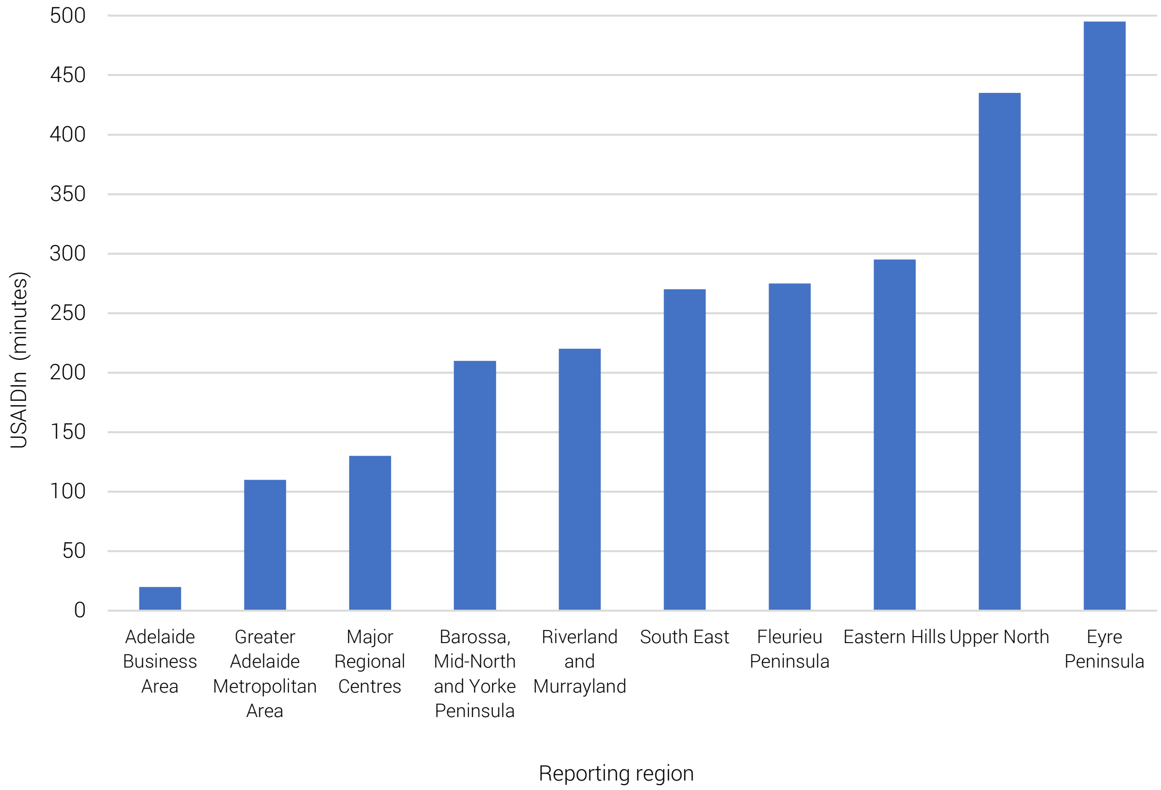
SA Power Networks is required to report on regional reliability. This promotes transparency and accountability, allows the Commission to monitor performance trends, and identify any areas that may require targeted improvements.

Reporting is required for ten regional categories that align with SA Power Networks' network planning regions. SA Power Networks reports to the Commission and the public on average reliability outcomes (measured as USAIDIn and USAIFIn) and provides reasons for variation in performance. The Commission regularly publishes information about regional reliability outcomes.[34]

Figure 4 illustrates average regional reliability performance. The reliability experienced by individual customers varies around these averages.

[34] See: Monthly tracking of reliability of SA Power Networks' electricity distribution services

Figure 3: 15-year average regional reliability performance (USAIDIn)




Data source: SA Power Networks 2022 Operational Performance Report to the Commission, OP 2.8

SA Power Networks is also required, by the Commission's Electricity Industry Guideline No. 1,[35] to identify and report on low-reliability feeders. Low-reliability feeders are identified by comparing the reliability of each individual feeder over the last two consecutive years with average reliability for that region. In the Code's definitions, low-reliability feeder '*means a feeder with a USAIDIn twice as high as the ten-year historical average to 30 June 2019 for that region, rounded to the nearest five minutes, for two consecutive regulatory years*.' This reporting requirement gives visibility of how reliability varies within each region.

As requirements for reporting on low-reliability feeders are made in Electricity Industry Guideline No. 1, rather than in the Code itself, the final decision is to move the definition of low-reliability feeder from the Code to Electricity Industry Guideline No. 1.

### 4.2.2 No decline in long-term regional reliability

There has been no decline in long-term regional reliability. In its 2021-22 Annual Reliability Performance Report to the Commission, SA Power Networks noted that *'there has been no declining trend … of any region's normalised reliability performance over the long term'.*[36] While there have been individual years of performance worse than the long-term historical average, these have been because of localised severe weather, or one-off non-systemic interruptions.[37]

35 Essential Services Commission of South Australia, Electricity Industry Guideline No. 1, Electricity Regulatory Information – Requirements – Distribution, Version G1/13.1

36 SA Power Networks, 2021-22 Annual Reliability Performance Report to the Commission, p. 9

37 SA Power Networks, 2021-22 Annual Reliability Performance Report to the Commission, p. 43

For example, in the South East, performance has been worse than the long-term historical average in each of the four years to 2020-21, due to localised severe weather (particularly lightning strikes) and animal interference (particularly possums). SA Power Networks has managed this by installing lightning resistant insulators and animal guards. This work is having an effect, with 2021-22 USAIDIn only slightly worse than the historical average, and 2021-22 USAIFIn inside the historical average.

As another example, in the Riverland and Murraylands, performance was significantly worse than the long-term historical average in 2021-22, due to three events - two localised severe weather events and one substation fault. There has been no decline in long-term historical performance.

### 4.2.3 New expenditure proposals to maintain regional reliability

SA Power Networks is developing expenditure proposals for the 2025 – 2030 period to maintain long-term reliability in some regions: the Eyre and Fleurieu Peninsulas, the South East and the Upper North.

To inform the 'focused conversation' stage of its community engagement, SA Power Networks prepared scenarios on different regional reliability outcomes, and estimated the associated repex and augex. All scenarios were published on its Talking Power website.

The early estimates presented during the 'focused conversations' provided an indication of the expenditure SA Power Networks may include in its regulatory proposal. The estimates suggest that a step change in expenditure will be proposed for the 2025 – 2030 period to maintain regional reliability.[38]

SA Power Networks indicated that repex planned to efficiently meet minimum network reliability standards for feeder categories (referred to in section 4.1.4) will not manage the impact of outages due to equipment failures in all regions. Outages due to equipment failures would continue to increase on the Eyre and Fleurieu Peninsulas.[39]

Augex planned to efficiently meet minimum network reliability standards for feeder categories (referred to in section 4.1.4) would not address the incidence of outages with other causes (such as localised severe weather or animal interference) or sufficiently manage the impact of outages when they occur in all regions. Regions most affected would be the Eyre and Fleurieu Peninsulas, the South East, and Upper North.[40]

SA Power Networks is also developing a proposal for additional expenditure across 2025 – 2030 for remediation works on low-reliability feeders.[41]

In SA Power Networks' early engagement on its regulatory proposal, consumers and stakeholders have indicated interest in and some support for this additional expenditure to maintain regional reliability.

More evidence of support for that expenditure has emerged through SA Power Networks' engagement program, including:

38 SA Power Networks, Focused conversation – managing a reliable, resilient and safe network – workshop 2, 2022, slides 58 – 62, and SA Power Networks, Focused conversation – managing a reliable, resilient and safe network – workshop 3, 2022, slide 70, detail about regional reliability improvement within Scenario 3. See also discussion in Essential Services Commission of South Australia, Electricity Distribution Code review – draft decision, January 2023, pp. 28-29

39 Repex planned to efficiently meet minimum network reliability standards for feeder categories would address the condition of the 33 kV network in the South East, SA Power Networks' submission to the Issues Paper notes concern about the condition of that network, pp. 23 -24

40 SA Power Networks, Focused conversation – managing a reliable, resilient and safe network – workshop 3, 2022, slide 69

41 SA Power Networks, Focused conversation – managing a reliable, resilient and safe network – workshop 3 2022, slide 73, detail about low-reliability feeder improvement within Scenario 3

- a recommendation for the People's Panel on repex and augex from the participants in the 'focused conversation' on network reliability, resilience and safety,
- results of willingness to pay research on consumer preferences for the reliability work program, and
- findings of the deliberative 'people's panel' which weighed the expenditure recommendations from each 'focused conversations' stream.

The AER may include in its distribution determination, expenditure other than that which is required to meet regulatory obligations, including in cases where there is demonstrated consumer support for that expenditure.

### 4.2.4 Minimum network reliability standards for specific regions

The final decision is to continue to require regional reporting, and monitoring of reliability outcomes for regions, across the 2025 – 2030 period.[42] No minimum network reliability standards will be established for specific regions. The Commission will only consider minimum network reliability standards for specific regions if and when there is strong evidence of sustained decline.

The Commission has previously set performance targets to drive reliability improvements in specific regions. It did so for Kangaroo Island in the 2010 – 2015 period. There, historical reliability performance of the distribution network had declined: average duration of outages were typically three to five times greater than on other parts of the rural network in South Australia. A specific target was set, on the basis that the Island's particular characteristics and the historical performance experienced by customers justified special treatment.[43]

In the Code review ahead of the 2020 – 2025 period, the Commission considered and decided against setting minimum network reliability standards for regions instead of feeder categories. The reasons for that decision remain valid:

- there is no evidence of sustained decline in regional performance, SA Power Networks has managed regional reliability within the existing distribution determination
- consumers remain generally satisfied with reliability, and are sensitive to cost increases, regional standards may affect costs over time
- the reporting regime can deliver the required visibility around regional performance, and communication, accountability and transparency
- changes in technology, such as Stand-alone Power Systems (SAPS), may support regional reliability.[44]

The Commission's expectation remains that SA Power Networks will manage regional reliability within its overall distribution determination.

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[42] Continuation of monitoring and reporting on regional outcomes is consistent with the Commission's recommendation in its 2017 Inquiry into reliability and quality of electricity supply on the Eyre Peninsula

[43] See the Commission's 2008 decision, South Australian Electricity Distribution Service Standards 2010 – 2015, pp. 61-62; also see the Commission's 2019 SA Power Networks reliability standards review – final decision, pp. 24, 55

[44] See full discussion in the Commission's 2019 SA Power Networks reliability standards review – final decision, pp. 23-25

## 4.3 Stand-alone Power Systems

The final decision is to not set minimum network reliability standards for Stand-alone Power System (**SAPS**) feeders because these are provided for by the national regulatory framework. The National Electricity Rules (**NER**) require that SA Power Networks must develop, publish and comply with SAPS reliability performance targets.

However, the Commission will require that SAPS feeders are included in regional reliability reporting and, once a SAPS feeder has been established for two years, it must be considered in identification of and reporting on low-reliability feeders.

GSL payments for the connection of new supply addresses and the duration and frequency of interruptions will apply to all distribution customers, including those on SAPS feeders.

Stand-alone Power Systems are electricity generation and distribution systems that are not physically connected to the national electricity grid but are still part of the NEM. Under recent changes to the NER, SA Power Networks may consider using a SAPS as an option to upgrade part of its network.[45] These changes do not affect existing SAPS that are not part of the NEM, such as small-scale distributors licensed by the Commission.

Each jurisdiction can prescribe how the SAPS framework applies; in South Australia the framework applies State-wide.[46] SA Power Networks is exploring use of SAPS. It envisages that very few customers, possibly fewer than ten in total, will move to SAPS in the current or next regulatory period.[47]

The national framework requires that SAPS customers are given the same consumer protections as those on the interconnected network.[48] The Commission has considered the need to extend the Code's minimum network reliability standards and GSL scheme to SAPS customers.

### 4.3.1 Minimum network reliability standards for SAPS customers

The NER require SA Power Networks to develop, publish and comply with SAPS performance and supply standards before converting any customer to SAPS supply.[49] The SAPS performance and supply standard must address reliability, and include performance targets for the frequency and duration of supply interruptions, and for expected load not served.[50]

SA Power Networks must develop those performance targets with regard to the SAPS quality of supply principle.[51] That principle requires that the reliability of supply for SAPS customers should be no worse than if they were served by the interconnected network.[52]

45 Australian Energy Regulator, Updating instruments for regulated stand-alone power systems, Final decision, August 2022
46 See National Electricity (South Australia) (Local Provisions) Variation Regulations 2021, and the Department for Energy and Mining's Consultation on South Australian implementation of SAPS
47 SA Power Networks, p. 24. Also see the Department for Energy and Mining's 2021 Consultation on South Australian implementation of SAPS, discussion about candidate sites identifies four potential sites, each with one or two customers, pp. 6-8.
48 Australian Energy Regulator, Updating instruments for regulated stand-alone power systems, Final decision, August 2022
49 National Electricity Rules Clause 5.13B.1
50 National Electricity Rules Schedule 5.13
51 National Electricity Rules Clause 5.13B.1(d)(1)
52 Stand-alone power system quality of supply principle is a defined term, see National Electricity Rules Clause 5.10.2

The NER provides a structure for ensuring reliability outcomes for SAPS customers. Therefore, the Commission has made a final decision not to set minimum network reliability standards for SAPS customers. Doing so would duplicate, and risk inconsistency with, NER requirements.

It will be possible to distinguish SAPS customers from those on the interconnected network, because the AER has amended its Distribution Reliability Measures Guideline (**DRMG**) to include a new SAPS feeder category.[53] In that Guideline, a SAPS feeder *'means a feeder, or a group of circuits, that serves a regulated Stand-alone Power System (SAPS). To avoid doubt, there will be only one SAPS feeder for each regulated SAPS.'* [54]

With this addition, the DRMG contains five unique and mutually exclusive feeder categories: CBD feeders, urban feeders, rural short feeders, rural long feeders and SAPS feeders.

To date, the Code has set minimum network reliability standards for each feeder category defined in DRMG. The feeder categories allow for a distribution network to be segmented based on feeder line length, customer load and level of redundancy. The Commission's final decision means that, from 1 July 2025, minimum network reliability standards will be set for CBD feeders, urban feeders, rural short feeders and rural long feeders, but not SAPS feeders.

This position is consistent with that put in the SA Power Networks submission to the Issues Paper,[55] that the Commission does not need to be involved in regulating reliability standards for SAPS, noting that the national framework adequately provides for reliability outcomes in SAPS.

In its submission to the draft decision, SA Power Networks supported the Commission's decision to not set reliability standards for SAPS, on the basis that they are provided for by the national framework.[56]

### 4.3.2 Regional reliability reporting and SAPS customers

As discussed in section 4.2.1, the Code requires SA Power Networks to report on regional reliability outcomes for ten regional categories.

Each region contains customers served by different types of feeders. For example, in the Greater Adelaide Metropolitan Area there are customers served by CBD feeders, urban feeders, and rural short feeders. In the South East, there are customers served by urban feeders, rural short feeders and rural long feeders.

All customers must be included in reporting to give a complete picture of reliability in each region. For that reason, the Commission has made the draft decision that customers on SAPS feeders must be included in regional reliability reporting in the 2025 – 2030 period.

As discussed in section 4.2.1, the Code also requires SA Power Networks to identify and report on low-reliability feeders in each region. All feeders must be considered when identifying low-reliability feeders, in order to give a complete picture of how reliability varies within each region.

For that reason, the Commission has made the final decision that, in the 2025 – 2030 period, SA Power Networks must, after a SAPS feeder has been established for the necessary two regulatory years, consider it when identifying low-reliability feeders.

53 Australian Energy Regulator, Distribution Reliability Measures Guideline, August 2022
54 Australian Energy Regulator, August 2022, Distribution Reliability Measures Guideline, August 2022, p. 6
55 SA Power Networks submission to Issues Paper, pp. 24-25
56 SA Power Networks submission to Draft Decision, covering letter

### 4.3.3 GSL payments for SAPS customers

*Connection of new supply addresses*

The Code contains a requirement for SA Power Networks to make GSL payments to customers where timeframes for the connection of new supply addresses are not met.[57]

Under the revised national framework, SA Power Networks will be able to connect new customers to a SAPS where the cost is lower than connecting that customer to the interconnected network.[58]

The Commission's final decision is that these GSL payments will apply to all customers seeking connection of a new supply address to SA Power Networks' distribution network, including those connecting to the interconnected network and those connecting to a SAPS.

*Duration and frequency of interruptions*

The Code contains a requirement for SA Power Networks to make GSL payments to customers where thresholds for the frequency and duration of supply interruptions are exceeded.[59]

The Commission's final decision is that these GSL payments will apply to customers connected to SA Power Networks' interconnected network and to customers connected to a SA Power Networks' SAPS.

The Code provides for certain interruptions to be excluded. Among the exclusions are interruptions caused by transmission and generation failures. These exclusions will not apply for customers supplied by SAPS feeders, where the whole system is managed as a distribution service.

As shown in the revised version of the Code that accompanies this final decision, Clause 2.3.1(c)(i)(A) and the definition of 'interruption' have been amended to reflect this. These amendments are consistent with the changes to exclusions set out in the DRMG at section 3.3. The wording in the revised Code has been amended for clarity since the draft decision.

Further, definitions of 'Regulated SAPS' and 'SAPS feeder' have been added to the Code. The definition of 'feeder' has also been updated.

The Issues Paper asked stakeholders to consider if there are practical issues that exist in applying the existing GSL scheme in SAPS. SA Power Networks supported extending the GSL scheme to SAPS customers, and considered that there are no practical issues that must be addressed to do so. [60]

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57 Clause 2.3.1 (a)

58 Australian Energy Regulator, Updating instruments for regulated stand-alone power systems, Final decision, August 2022, p. 10.

59 Clause 2.3.1 (c)

60 SA Power Networks submission to Issues Paper, pp. 24-25.

## 4.4 Network planning requirements

> The final decision is that no network planning requirements for supply reliability will be introduced to the Code at this time.
>
> The Commission will meet with the AER as it makes its distribution determination for the 2025 – 2030 period to understand how it assesses any capital expenditure proposals which are not supported by a strictly probabilistic approach to network planning.
>
> The Commission will revisit the matter of whether to include network planning requirements for supply reliability as Code obligations ahead of the 2030 – 2035 period.

The final decision is that no network planning requirements for supply reliability will be introduced to the Code at this time.

The Commission supports the use of economic analysis in network planning to establish the value to customers of network investment (that is, a probabilistic approach to network planning) rather than only relying on a fixed, deterministic approach.

However, the Commission recognises that network planning decisions also need to be informed by analysis of costs and benefits that cannot be readily quantified, and by analysis of risk and uncertainty. In practice, a more flexible approach to probabilistic planning is necessary. Evidence suggests that the AER will take this type of approach in assessing forecast capital expenditure.

In early 2024, the Commission will meet with SA Power Networks to identify projects in its regulatory proposal that it considers important to delivering reliability outcomes for consumers but is concerned will not be considered prudent based on strictly probabilistic network planning. The Commission will then monitor how the AER treats those projects in making its distribution determination for the 2025 – 2030 period.

The Commission will revisit the matter of including network planning requirements for supply reliability in the Code ahead of the 2030 – 2035 period.

### 4.4.1 Submissions to draft decision

In its submission to the draft decision, SA Power Networks reiterated its concern that some projects it considers necessary to respond to increased customer demand and the associated network security risks (based on its deterministic network planning criteria) may not be considered prudent by the AER.[61]

SA Power Networks is concerned that, in making its distribution determination, the AER will determine whether projects are prudent based on economic Value of Customer Reliability (VCR) analysis (that is, the AER will require a probabilistic approach to network planning).

In its submission to the draft decision, SA Power Networks suggested that the Commission specify network planning criteria in the Code, to ensure supply reliability outcomes when a major piece of equipment fails.[62]

This concern was also raised in SA Power Networks submission to the Issues Paper, which requested that a simplified version of its current network planning criteria be incorporated in the Code.[63]

[61] SA Power Networks submission to Draft Decision, pp. 6-8
[62] SA Power Networks submission to Draft Decision, p. 8
[63] SA Power Networks submission to Issues Paper, p. 7, 26-28

### 4.4.2 Response

The Commission has considered whether it has a role to prescribe how SA Power Networks delivers against Code requirements, in addition to prescribing the outcomes it needs to deliver.

SA Power Networks currently uses internal network planning criteria to plan the capacity of its network. The criteria relate to types of asset: substations, distribution feeders, and sub-transmission system systems. The criteria define the desired level of redundancy, whether that be maintaining the system with normal capacity or given a contingency, in various demand scenarios.[64] The criteria represent a deterministic approach to network planning.

SA Power Networks applies its network planning criteria to identify where capacity constraints may emerge as demand on the network changes. If constraints eventuate after a period of monitoring, SA Power Networks will resolve them using the least-cost option. It relies on the network planning criteria to maintain underlying network reliability, the foundation for delivering against the Commission's minimum network reliability standards.

Application of the network planning criteria also delivers a level of resilience to high-impact low-probability (**HILP**) events. HILP events may arise from severe weather, unexpected equipment failure, or the convergence of several more likely events (such as an unexpected failure of one network element when another is offline for maintenance). In the context of reliability outcomes, the 'high-impact' of these events refers to widespread and long-duration outages (**WALDOs**).

The Code's current minimum network reliability standards do not prescribe how SA Power Networks should plan the network. The Code sets output standards for normalised performance. The impact of Major Event Days (**MEDs**) is excluded from assessing normalised performance. The Code requires that SA Power Networks apply its best endeavours to managing reliability outcomes on MEDs.

SA Power Networks has responsibility for assessing the risk and uncertainty around HILP events, planning the extent to which the network is resilience to HILP events, and planning the appropriate response should one occur. These matters would form part of an assessment of whether SA Power Networks has applied its best endeavours, should one be required.

SA Power Networks noted that the AER critiqued the use of its network planning criteria in its 2020 – 2025 distribution determination, and is concerned that the AER may not provide for expenditure to meet those criteria in the 2025 – 2030 period.[65] It is concerned that the AER favours an alternative, probabilistic approach to network planning, which seeks to establish the value to customers of addressing any individual constraint or possible HILP event. This probabilistic approach to network planning is widely used amongst NEM distributors.

SA Power Networks has suggested that beyond 2030, this probabilistic approach would result in a lower level of expenditure and drive deterioration in network resilience, particularly in relation to HILP events.[66] It is concerned this would not meet customer expectations, and has requested that the Commission specify network planning criteria in the Code, to ensure supply reliability outcomes when a major piece of equipment fails.[67]

The Commission has sought to understand how the AER may assess forecast capital expenditure.

In setting revenue caps, the AER is required to provide for expenditure to meet regulatory reliability obligations and, to the relevant extent, maintain reliability.[68] For SA Power Networks, this means the

[64] SA Power Networks, Distribution Annual Planning Report 2021/22 to 2025/26, pp. 40-47
[65] SA Power Networks submission to Issues Paper, p. 7, 26-28; submission to Draft Decision, pp. 6-8
[66] SA Power Networks submission to Issues Paper, p. 7, 26-28
[67] SA Power Networks submission to Issues Paper, p. 7, 26-28; submission to Draft Decision, p. 8
[68] See NER 6.5.7 – Forecast capital expenditure

AER must consider the existing regulatory obligations made in the Code. This includes the requirement that SA Power Networks apply its best endeavours in pursing reliability performance outcomes, in both normal and extreme conditions.

In establishing the efficient level of expenditure required to meet this requirement, the AER establishes the value to customers of capital expenditure (that is, takes a probabilistic approach).[69] However, the AER recognises a role for other supporting evidence.[70] This suggests the AER will not require a strictly probabilistic approach to network planning.

In relation to planning for network resilience, additional supporting evidence may include:

- studies of the impact, likelihood and nature of HILP events
- analysis of options for preparing for and/or responding to those events
- quantitative assessment of the benefits and costs of various options (using existing Values of Customer Reliability (VCRs), and in some cases additional willingness-to-pay research), and
- qualitative assessment of consumer preferences as evidenced in customer engagement.

The Commission supports the use of economic analysis in network planning to establish the value to customers of network investment (that is, a probabilistic approach). However, the Commission also considers that probabilistic planning needs to be flexible, consider costs and benefits of expenditure that cannot be readily quantified, and appropriately consider and respond to risk.

The Commission will monitor the AER's approach to assessing forecast capital expenditure that SA Power Networks considers important to delivering reliability outcomes but is concerned will not be considered prudent based on strictly probabilistic network planning. In early 2024, the Commission will meet with SA Power Networks to identify such expenditure. The Commission will then monitor how the AER treats those projects in making its distribution determination for the 2025 – 2030 period.

The Commission will revisit the matter of including supply reliability standards in the Code ahead of the 2030 – 2035 period.

[69] For example, the AER requires a probabilistic approach in planning replacement expenditure, and for improvements made to pursue STPIS incentives. See: Industry practice application note – Asset replacement planning – January 2019 and Service Target Performance Incentive Scheme – December 2018.This extends to the AER's approach to assessing resilience-related expenditure. See Australian Energy Regulator 2022, Network resilience – note on key issues.

[70] Confirmed in discussions with the Australian Energy Regulator, see also Australian Energy Regulator 2022, Network resilience – note on key issues, pp. 11-12

## 4.5 Minimum customer service standards

The final decision is to add two new minimum customer service standards to the Code for the 2025 – 2030 period.

The new service standards relate to telephone responsiveness and first contact resolution for the General Enquiries line and the Builders and Contractors line.

The existing service standard for telephone responsiveness will remain, but apply only to other SA Power Networks telephone lines (most significantly, the Faults and Emergencies line). The service standard for written enquiry responsiveness remains unchanged.

Together, these four service standards will provide a baseline for SA Power Networks' customer service outcomes. The Commission will continue to require monitoring and reporting on customer satisfaction with communication quality.

The current Code contains two minimum customer service standards. These relate to average annual performance, in normal operations:

- SA Power Networks must use its best endeavours to respond to 85 percent of telephone calls within 30 seconds.[71]
- SA Power Networks must use its best endeavours to respond to 95 percent of written enquiries within five business days.[72]

Since 2020-21, SA Power Networks has also been obliged to monitor and report on customer satisfaction with communication quality.[73] Customer satisfaction is reported against an industry benchmark, using the Customer Service Benchmarking Australia (**CBSA**) customer satisfaction measure and its sub-measures (relating to planned and unplanned interruptions, new connections and complaints).

These Code requirements complement the provision in the National Energy Retail Rules (**NERR**) which require that distributors maintain a 24-hour fault reporting line.[74] SA Power Networks' Faults and Emergencies reporting line is one of its five telephone lines.

In reviewing Code requirements, the Commission's approach in previous reviews has been to provide minimum customer service standards as a baseline for SA Power Networks' customer service outcomes.

The Commission's position set out in the draft decision was to revise minimum service standards when clearly outdated or if there is evidence that they are a barrier to improving customer service, as measured by the metrics SA Power Networks uses within its business.

The draft decision noted that new and innovative customer service measures may be layered on top of the minimum customer service standards set by the Commission. This may be done through SA Power Networks' internal business practices, or by establishing parameters in the AER's Customer Service Incentive Scheme (**CSIS**).

71 Clauses 2.1.1, 2.1.2, 2.1.3 and 2.1.5
72 Clauses 2.1.1, 2.1.4 and 2.1.5
73 See Electricity Industry Guideline No. 1, OP 1.3
74 NERR section 85. The National Energy Retail Law (Local provisions) regulations 2013, in section 7, establish minimum customer service standards for retailers but not for distributors. These relate to responsiveness to written and telephone enquiries.

### 4.5.1 Performance against minimum customer service standards

SA Power Networks performs well against its minimum customer service standards. Across the 12 years to 2021-22, an average of 89 percent of telephone calls have been answered within timeframes. The number of telephone calls made to SA Power Networks has declined over time.

In the same 12-year period, an average of 98 percent of written enquiries have been answered within timeframes. Since 2020-21, the definition of written enquiry has expanded to include those made using the distributor's website and social media direct messaging.

In 2020-21 and 2021-22 customer satisfaction was at or above the industry benchmark for the overall customer satisfaction measure and all sub-measures except complaints.

### 4.5.2 Customer service measures used internally by SA Power Networks

SA Power Networks' communication with customers has expanded beyond telephone and written enquiries. It also communicates with customers through its website, SMS messages, social media (Facebook, Twitter, Instagram, LinkedIn and YouTube) and other media (print, radio and online).

The range of measures SA Power Networks uses to monitor and improve customer service has also expanded. Within its business, SA Power Networks focuses on the CBSA measures. It also monitors the quality of telephone interactions (first call resolution), feedback and engagement through social media, complaint issues, and the way major network events impact customer service.[75]

### 4.5.3 AER customer service incentive schemes

SA Power Networks is incentivised to improve customer service by the AER's STPIS. The current 2020 – 2025 STPIS includes a customer service performance target that 78 percent of faults and emergency calls are answered within 30 seconds. SA Power Networks receives a financial incentive (or penalty) for performance against that target, with 0.5 percent of its revenue at risk.

Since July 2020, the AER has provided for distributors to propose a CSIS, as an alternative to the customer service component of the STPIS. Distributors can propose measures to be included in the CSIS, which must satisfy guidance principles set out by the AER and be supported by customers.[76]

Distributors that have a CSIS in place use different types of measures:

- AusNet, has CSIS parameters for each of the CBSA sub-measures (satisfaction regarding communication on planned and unplanned outages, customer service for new connections and customer service in managing complaints)[77]
- CitiPower, PowerCor, and United Energy, have CSIS parameters for SMS communication for unplanned outages, frequency and duration of planned outages and customer service in telephone answering.[78]

This illustrates different approaches within distribution businesses to understanding and managing the aspects of customer service that matter to customers.

75 SA Power Networks 2022, Focused conversation – customer experience and interactions – workshop 2 presentation, slide 17

76 See Australian Energy Regulator 2019, Customer Service Incentive Scheme explanatory statement and scheme design

77 See Australian Energy Regulator 2021, Final Decision, AusNet Services Distribution Determination 2021 to 2026, Attachment 12, Customer service incentive scheme

78 See AER 2021, Final Decision, CitiPower, PowerCor and United Energy Distribution Determination 2021 to 2026, Attachment 12, Customer service incentive scheme

### 4.5.4 Engagement on revised customer service measures

SA Power Networks has engaged with customers on its use of customer service measures, including which measures best define minimum levels of service (for consideration in this Code review) and which might be used in the CSIS to incentivise improvements. [79]

SA Power Networks considers that the Code's minimum customer service measures have become less relevant to customers over time. [80] In particular, SA Power Networks considers that the telephone responsiveness measure is no longer appropriate, and that measures of customer satisfaction (measured since 2018) and first contact resolution (measured since the start of 2022) are more important.[81]

The draft decision noted that more evidence of customer views on service measures would emerge through the remainder of the SA Power Networks' engagement program, which the Commission may consider in making its final decision.

### 4.5.5 New service standards for telephone responsiveness and first call resolution

The draft decision set out that the Commission may consider revised minimum service standards if there is evidence they are a barrier to improving customer service as measured by the metrics SA Power Networks uses within its business. There is evidence this may be the case in relation to existing telephone service standards.

SA Power Networks' customer engagement suggests that resolving customer's queries in the first call (first call resolution) is important to customer satisfaction. It also suggests that, in relation to some types of queries, a slight increase in call wait times will not reduce customer satisfaction.

In response to this, SA Power Networks has been measuring and working to improve the rate of first call resolution on two of its phone lines (General Enquiries and Builders and Contractors) since January 2022.[82] It has made this change without increasing costs, by allowing telephone responsiveness to decline slightly.[83]

Telephone responsiveness for these two phone lines fell from 90 percent of calls answered within 30 seconds (and 92 percent answered within 60 seconds) in January 2022 to 75 percent of calls answered within 30 seconds (and 81 percent answered within 60 seconds) in March 2023. This has not adversely affected customer satisfaction. This suggests that maintaining the Commission's current telephone responsiveness service standard, while also improving first call resolution, would result in unnecessary costs. The importance of keeping the costs of service neutral was highlighted in the SACOSS submission to the draft decision.[84]

Therefore, the Commission has made the final decision to change the telephone service standard for the General Enquiries phone line and the Builders and Contractors phone line. These lines account for 30 percent (General Enquiries) and 14 percent (Builders and Contractors) of calls to SA Power Networks.

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79 SA Power Networks 2022, Customer Experience and Interactions focused conversations engagement stream
80 SA Power Networks submission to Issues Paper, pp. 7–8, 34 – 35
81 SA Power Networks submission to Issues Paper, pp. 7–8
82 Initially, between January 2022 and August 2023, SA Power Networks allowed customers to answer 'yes' or 'no' when asked in a survey if their query had been resolved. From September 2023 onwards SA Power Networks will allow the answers 'yes', 'no' and 'too early to tell'.
83 SA Power Networks' operational performance report to the Commission for March 2023, showed year-to-date performance of 83.2 percent for the percentage of all telephone calls answered within 30 seconds.
84 See South Australian Council of Social Service, submission to Draft Decision

The final decision is to:

- introduce a new first call resolution service standard for calls to the General Enquiries phone line and the Builders and Contractors phone line, and
- introduce a new telephone responsiveness service standard for calls to the General Enquiries and Builders and Contractors phone lines.[85]

The service standards will be that SA Power Networks must use its best endeavours to meet performance targets. The Commission will engage with SA Power Networks on its protocols for measuring first call resolution and establish performance targets. Performance targets will be based on historical performance. They will be published for consultation in January 2025 and finalised before the revised Code commences in July 2025.

The existing telephone responsiveness service standard, which requires that SA Power Networks must use its best endeavours to respond to 85 percent of telephone calls within 30 seconds, will be retained.[86] This will be adjusted to apply to calls to other numbers identified in SA Power Networks' customer enquiries and complaints procedures approved by the Commission (primarily the Faults and Emergencies line, which receives 55 percent of calls to SA Power Networks).[87]

Response times of calls to the Faults and Emergencies line are important to customer satisfaction, and SA Power Networks' approach to responding to those calls is well-established and effective. It is not necessary to improve first call resolution for those calls.

[85] The Commission introduced a first contact resolution service standard for SA Water in 2020. The service standard 'Account enquiry telephone calls resolved at first point of contact' has a performance target of > 85 percent. The Commission also relaxed the telephone responsiveness service standard performance target, from > 85 percent of calls answered within 30 seconds to > 85 percent of calls answered within 60 seconds. The performance target was relaxed because there was evidence the change would not affect customer satisfaction and allow improvement in first contact resolution without an increase in cost. See: Essential Services Commission of South Australia, SA Water Regulatory Determination 2020, Final Determination: Statement of reasons, 2020, pp. 101-103

[86] Clauses 2.1.1, 2.1.2, 2.1.3 and 2.1.5

[87] As per OP1.1. of Electricity Industry Guideline No. 1. There are five numbers listed in SA Power Networks' 2015 Complaints, Enquiries & Dispute Management process: General Enquiries - 13 12 61, Builders and Contractors - 1300 650 014; Faults and Emergencies - 13 13 66; Street Light Out Service - 1800 676 043; and the Customer Feedback Line - 1800 088 667.

# 5 Distributed energy resources

Distributed energy resources (**DER**) are energy units or systems that are located on the consumer side of the meter, commonly located on houses or businesses, including rooftop PV panels, batteries, electric vehicles, energy management systems and larger stand-alone generators. DER may be operated by individual customers, or coordinated as part of a Virtual Power Plant (**VPP**).

VPPs operate within the SA Power Networks' distribution network and coordinate DER to deliver electricity and other power system services. Their operations require registration with the Australian Energy Market Operator (**AEMO**) and a retail authorisation issued by the Australian Energy Regulator (**AER**). They are not currently required to have a generation licence issued by the Commission.[88]

Use of DER continues to grow in South Australia. The extent and rapid uptake of DER is contributing to the diversification and decarbonisation of South Australia's energy supply. Customers with DER may benefit directly by reducing electricity imports from the distribution network, and by exporting and selling excess electricity. The National Electricity Rules (**NER**) now recognise exports from DER as one of the core services distributors provide to customers.[89]

DER are fundamentally changing the operating environment for SA Power Networks' distribution system. This requires managing:

- consumer expectations and values around use of the network for exporting energy
- localised network congestion
- system security issues related to when peak and low demand occur, and
- network coordination of DER generation.

As explained in the Issues Paper, this Code review has considered whether there is a gap in the regulation of DER that needs to be addressed through the Commission's regulatory framework.[90]

National and State regulatory frameworks are evolving in response to the risks posed by the interaction of DER with the distribution network.

To identify gaps in that response, the Commission has consulted with the Australian Energy Market Commission (**AEMC**), AEMO, AER, Department for Energy and Mining (**DEM**), Energy and Water Ombudsman South Australia (**EWOSA**), the Office of the Technical Regulator (**OTR**) and SA Power Networks.

Consultation included discussion on identified risks including how customers with DER pay for exports, how localised network congestion or voltage issues may limit export capacity, power quality issues resulting from voltage variations, and the provision of timely and accessible information for customers about export services.

Analysis presented in the Issues Paper found that most of the risks are being, or will be, addressed elsewhere in the national or State regulatory instruments.

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88 The licensing framework through which the Commission can impose technical conditions on some generators is under review (see Department for Energy and Mining, Review of the South Australian Electricity Licensing Framework, 2022). While this review is being conducted, a temporary class exemption is in place for VPPs, electric vehicle charging operators and generators with capacity of 5MW or less (see Essential Services Commission of South Australia, Electricity generation licence exemption, 2021).

89 Australian Energy Market Commission, Access, pricing and incentive arrangements for Distributed Energy Resources, 2021. This change introduces consumer protections for export services to the national framework.

90 See Issues Paper, pp. 4-5 and Issues Paper, Appendix 1.

That analysis considered recently-introduced consumer protections related to the provision of export services, which were included in the AEMC rule change to recognise export services as a core distribution service. [91] These include expanding capacity for export services (by requiring distributors to plan for efficient provision and through possible development of financial incentive arrangements[92]), prohibiting zero-export offers to small customers (except where inefficient) and publication of annual reports on export services (from late 2023).

The AEMC considers that export service standards are not likely to be necessary within the national consumer protection framework but that some jurisdictions may seek to set export service standards to meet their own circumstances.[93] The Commission will monitor implementation of the national consumer protection framework for export services to identify whether additional protections are needed for South Australian consumers.

Given that most risks associated with DER are being addressed elsewhere in the national or State regulatory frameworks, this review has focused on the Code's existing provisions for DER (which relate to the connection of embedded generators), with the goal of removing duplication with, and resolving inconsistencies between, the Code and other national and State instruments. Those findings are presented in section 5.1.

The Issues Paper sought comments about whether, from the consumer's perspective, there were risks posed by the interaction of DER with the distribution network that the Commission had not considered, and whether those risks may be best addressed by the Commission.

SA Power Networks' submission identified three areas of risk to consumers, which in its view are best addressed by the Commission. These are risks arising from: the operation of VPPs; lack of continuity around connection agreements when the ownership of embedded generating units changes; and, network control at times of negative demand (when generation from DER is greater than scheduled demand). These matters are addressed in section 5.2.

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[91] Australian Energy Market Commission, Access, pricing and incentive arrangements for DER, 2021. See also: Australian Energy Regulator, Incentivising and measuring export service performance, 2022

[92] After initial consideration, the Australian Energy Regulator has indicated it will initiate a full review of incentive arrangements for export services by 2027 (See Australian Energy Regulator, Incentivising and measuring export service performance, 2022, p. 5)

[93] Australian Energy Market Commission, Access, pricing and incentive arrangements for Distributed Energy Resources, 2021, pp. 42, 52-53

## 5.1 Review of existing provisions for connection of embedded generators

The final decision is to:

- remove clauses 3.2 – 3.8 from the Code, which relate to the connection process and associated financial charges, matters which are now addressed in the National Electricity Rules (**NER**)
- remove clauses 3.9, 3.10.1 (a) and (c), 3.11 3.12, 3.14, 3.15 and 3.16, which relate to technical aspects of the connection of embedded generators that are now addressed by other regulatory provisions or are otherwise no longer necessary
- remove clauses 3.10.1(b), 3.13 and 3.17, and recommend to the Technical Regulator that it considers whether these matters should be provided for in the broader State framework, before the new Code commences on 1 July 2025.

The Code's existing provisions for the connection of embedded generation to the distribution network cover the connection process and associated financial charges, as well as technical requirements for connection.

The connection process and associated financial charges for embedded generators are now covered in the national framework, and the final decision is to remove that content (clauses 3.2 – 3.8). SA Power Networks supports removing those clauses.[94]

Many of the technical requirements for connection made in the Code (clauses 3.9 – 3.17) are now duplicated either directly or in intent by requirements in the broader national and State regulatory framework.

In particular, many of the clauses are replicated, with more detail and specificity, in SA Power Networks' 2022 Service and Installation Rules (**SIR**) and associated Technical Standards.

In May 2022, the Technical Regulator approved changes to SA Power Networks' SIR, which elevated the status of the associated Technical Standards. SA Power Networks' Technical Standards are now Technical Installation Rules (**TIR**) and are called up by and enforceable under the *Electricity (General) Regulations 2012* (**Electricity Regulations**). Further, each Technical Standard is approved by the Technical Regulator.

The Technical Standards are:

- TS129 – Small Embedded Generator Connections Technical Requirements – Capacity not exceeding 30 kilovolt-amperes (**kVA**)
- TS132 – Low Voltage Embedded Generation Connection Technical Requirements – Capacity above 30kVA
- TS133 — High Voltage Embedded Generation Connection Technical Requirements, and
- TS134 — Communication Systems (including Supervisory Control and Data Acquisition (**SCADA**) for Embedded Generation.

[94] SA Power Networks submission to Issues Paper, p. 17

The SIR apply to new installations, alterations and repairs or additions to existing installations that are connected to the distribution network (see SIR 1.2). The SIR also provide a framework for ongoing compliance (see SIR 9.2.5), although demonstration of ongoing compliance is not explicitly required for embedded generators with capacity less than 30kVA connected to the low voltage network. [95]

The Commission's assessment of the extent to which there is duplication or inconsistency between the Code and other regulatory instruments has been informed by advice provided by Engevity, published alongside this final decision.

The final decision also removes clauses 3.9, 3.10.1 (a) and (c), 3.11 3.12, 3.14, 3.15 and 3.16 on the basis they are now addressed by other regulatory provisions or are otherwise no longer necessary. Reasons for removing each of these clauses are documented in Appendix 2.

There are three clauses that are not addressed by other regulatory provisions: clauses 3.10.1(b), 3.13 and 3.17. This final decision also removes those clauses from the Code. The Commission will recommend to the Technical Regulator that it considers whether these matters should be provided for in the broader State framework.

The Commission has considered the intent and drafting of these clauses (see discussion in Appendix 2) and will provide its analysis to the Technical Regulator.

It is appropriate that these matters are addressed elsewhere, because the Commission no longer has responsibility for the technical regulation. Responsibility for technical regulation of the distribution network sits with the Technical Regulator and the AER, with SA Power Networks and the AEMO having operational responsibilities.

This change in the Commission's role regarding technical regulation was recognised by changes made to the *Electricity Act 1996* (**Electricity Act**) in 2017 that moved oversight of SA Power Networks' Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**) from the Commission to the Technical Regulator.[96] The Commission no longer approves connection agreements for embedded generators, and the licensing framework through which the Commission can impose technical conditions on some generators is under review.[97]

These remaining technical matters may be addressed in the next version of the Electricity Regulations (noting that the current Electricity Regulations expire in September 2023), or in SA Power Networks' Technical Standards. As the next version of the Code will apply from 1 July 2025, there is time for the Technical Regulator to consider how to provide for those matters, and to make any changes to the relevant instruments.

In its submission to the draft decision, SA Power Networks accepted the Commission's decision to remove the technical requirements in Chapter 3 from the Code, and noted its willingness to work with the Commission and the Technical Regulator to retain any necessary obligations currently in the Code in other jurisdictional instruments.[98]

[95] Currently, TS132 and TS133 (at clause 7.3) require embedded generators to demonstrate ongoing compliance with the SIR and TS; demonstration of ongoing compliance is not explicitly required in TS129 (which applies to embedded generators with capacity less than 30kVA connected to the low voltage network).

[96] See Essential Services Commission of South Australia - Changes to safety, reliability, maintenance and technical management plan and switching manual requirements

[97] See: Department for Energy and Mining, Review of the South Australian Electricity Licensing Framework, 2022

[98] SA Power Networks, submission to Draft Decision, p. 4

## 5.2 Other areas of risks to consumers

Regulatory frameworks are evolving in response to the risks posed by the interaction of DER with the distribution network. Analysis presented in the Issues Paper found that most of the risks are being, or will be, addressed elsewhere in the national or State regulatory frameworks.

SA Power Networks' submission to the Issues Paper identified three areas of risk to consumers, which in its view are best addressed by the Commission. These are risks arising from: the operation of VPPs; lack of continuity around connection agreements when the ownership of embedded generating units changes; and, network control at times of negative demand (when generation from DER is greater than scheduled demand).

Risks arising from the operation of VPPs and the lack of continuity around connection agreements when the ownership of embedded generating units changes are discussed below.

Regarding network control at times of negative demand, SA Power Networks submitted in response to the Issues Paper that *'it would be useful for the Code to expressly acknowledge that SA Power Networks may employ appropriate strategies to manage this scenario'.*[99] The Commission does not consider it necessary to address how SA Power Networks may manage small generators in this scenario; this is currently managed through directions from AEMO via ElectraNet and this is sufficient. No further comments on this matter were included in SA Power Networks' submission to the draft decision.

### 5.2.1 Risks posed by the operation of VPPs

> The final decision is that the Commission will not introduce Code provisions to manage the risks to consumers associated with Virtual Power Plants (VPPs) operating within the distribution network. Provisions to address those risks are expected to be made as the result of two other reviews.

Virtual Power Plants (VPPs) operate within the SA Power Networks distribution network and coordinate DER to deliver electricity and other power system services.

Between 2019 and 2021, AEMO coordinated a series of VPP demonstrations to inform the design of associated regulatory frameworks. At the end of that trial, there were four participating South Australian VPPs with a combined capacity of 27MW.[100]

Coordination of DER by a VPP may impact the security, reliability, and quality of electricity supply. For consumers, these potential impacts may increase the risks that outages may occur, power quality may be affected, and that energy exports may be curtailed.

There are also risks to consumers arising from the lack of a direct contractual relationship between VPPs and the distributor. Individual customers have a contractual agreement with the distributor (their connection agreement[101]), and another with the VPP operator. Through the latter agreement, participants effectively delegate some matters regarding operation and performance of their DER equipment that are addressed in the connection agreement. This is at the risk of the individual customer.

In its submission to the Issues Paper, SA Power Networks sought consideration of the potential impact of VPPs on the distribution network, and the subsequent impact on consumers: '*It must be noted that*

[99] SA Power Networks submission to Issues Paper, p. 20

[100] Australian Energy Market Operator National Electricity Market Virtual Power Plant Demonstrations Knowledge Sharing Report 4, 2021, p. 20

[101] Typically each customer in a Virtual Power Plant has Distributed Energy Resources with a small capacity, and connection is made using SA Power Networks' Model Standing Offer or the Deemed Standard Connection Contract (National Energy Retail Law Schedule 2).

*DER, when controlled by a VPP, effectively operate together, and as such can have a greater impact on the distribution system, than when operating independently.'* [102]

The potential impacts of VPPs on the distribution system, and the risks they pose to consumers, could be managed by requiring an operating agreement between each VPP operator and SA Power Networks.

In its submission to the Issues Paper, SA Power Networks put the view that: '*We believe that there should be a requirement for a VPP/aggregator operator to negotiate an operating agreement with SA Power Networks to ensure that the simultaneous operation of the many individual generation plants does not adversely impact the distribution system and other customers.'* [103]

SA Power Networks also expressed this position in its submission to the DEM Review of the South Australian Electricity Licensing Framework.[104] In that submission, SA Power Networks proposed the requirement for each VPP to have an operating agreement with the distributor be made through the Electricity Act, with the Act specifying a role for the Commission to determine the terms of that agreement if necessary.[105]

That submission also noted SA Power Networks' support for the licensing of and additional conditions for VPPs: *'Further, we support additional conditions being incorporated into a VPP's generation licence in regard to compatibility, to ensure that the operation of an individual generation plant by the VPP does not result in that individual generating plant breaching its legal obligations.'* [106]

The Commission acknowledges the potential for operating agreements between a VPP operator and a distributor to:

- complement the existing agreements between the customer and the distributor, and the customer and the VPP operator
- make VPP operators directly responsible for some technical matters regarding the connection and operation of DER on a customer's premises (limiting the accountability of consumers for VPP actions)
- address technical matters specific to managing the impact of DER aggregated through VPPs on security, reliability and quality of supply within the distribution network (limiting the risk to consumers of outages or power quality issues), and
- contain provisions for rectifying instances of non-compliance, for dispute resolution, and for monitoring and reporting.

The Commission expects provisions for managing the risks to consumers associated with VPPs, which may include provisions for operating agreements, to be made as the result of two other reviews.

First, the DEM Review of the South Australian Electricity Licensing Framework.[107] That licensing framework, established by the Electricity Act, is administered by the Commission. The review is considering the role of the licensing framework with respect to risks posed by changes in technology.

[102] SA Power Networks submission to Issues Paper, p. 14
[103] SA Power Networks submission to Issues Paper, p. 15
[104] SA Power Networks submission to the Review of the South Australian Electricity Licensing Framework , p. 3
[105] SA Power Networks submission to the Review of the South Australian Electricity Licensing Framework , pp. 3-4
[106] SA Power Networks submission to the Review of the South Australian Electricity Licensing Framework, p. 4
[107] Department for Energy and Mining, Review of the South Australian Electricity Licensing Framework, 2022

VPPs are exempt from the need to hold a generation licence while the review is underway.[108] This follows an initial exemption which was in place during the AEMO VPP demonstration period.[109] The exemption is required because the combined capacity of VPPs exceeds the Electricity Act's statutory licensing exemption threshold of 100 kVA, but mandatory generation licence conditions are not particularly relevant or appropriate for VPPs.

The DEM review consulted on an Issues Paper (until February 2022). Its next stage is to publish an options paper.

Second, the AER is conducting a Review of Consumer Protections for New Energy Services.[110] Through that review, the AER is considering potential regulatory reforms which could mitigate the risks new energy products and services, including VPPs, pose to consumers. It may recommend changes to the National Electricity Rules (**NER**) and/or National Energy Customer Framework (**NECF**).

The AER review consulted on an Issues Paper (until May 2022) and published an Options Paper for consultation in October 2022. Its draft recommendations paper is due to be published in May 2023, and its final in August 2023.

As both reviews are likely to conclude before the revised Code applies (from 1 July 2025), the Commission has made a final decision not to introduce Code provisions to manage the risks to consumers associated with VPPs operating in the distribution network. The Commission will monitor the findings and recommendations of both reviews as they become available.

### 5.2.2 Continuity of connection agreements for embedded generators

The final decision is that the Commission will not introduce Code provisions that affect the terms and conditions that may be included in deemed standard connection contracts. The matter of which technical provisions should apply to the connection and operation of embedded generation in South Australia is best addressed by the Technical Regulator.

Further, the Commission will not introduce Code provisions that require continuity of connection agreements for the small group of generators for whom this is not already required by the national framework. This gap poses a low risk that can be managed by SA Power Networks.

Connection agreements set out terms for the connection of premises to the distribution network, and the supply and export of electricity. They address matters including obligations made under energy laws, operation of embedded generation, interruptions to and disconnection of supply. They are used to manage the potential impact of embedded generators on the distribution network.

All embedded generators have a connection agreement in place at the time of initial connection. The scope of connection agreements and process for establishing them is provided for in the NER:

- Chapter 5A sets out the connection process and nature of connection agreements for retail customers seeking to connect embedded generation. All embedded generators other than those required to register with the Australian Energy Market Operator (**AEMO**) are considered to be retail customers for the purpose of connection through Chapter 5A.

[108] Essential Services Commission of South Australia, Electricity generation licence exemption – Virtual Power Plant operations, electric vehicle charging operators, and sub-5MW operators, 2021

[109] Essential Services Commission of South Australia, Enrolled participants in the Australian Energy Market Operator's Virtual Power Plant demonstration program, 2019

[110] Australian Energy Regulator, 2022, Review of Consumer Protections for New Energy Services

- Chapter 5 sets out the connection process and nature of connection agreements for other operators seeking to connect embedded generation. Embedded generators required to register with AEMO must connect using the process in Chapter 5, and non-registered embedded generators may choose connection through Chapter 5 instead of Chapter 5A.

For retail customers connecting embedded generation that has capacity less than 10kVA per phase (less than 30kVA in total), SA Power Networks uses an AER-approved standard connection agreement, the Model Standing Offer 3602.[111] Agreements are negotiated for other types of connections.

When ownership or control of an embedded generator changes, a connection agreement with the new party is required. Embedded generators required to register with AEMO are required by the NER to maintain a connection agreement with SA Power Networks.

For embedded generators that are also customers, the National Energy Retail Rules (NERR) provide that a deemed standard connection contract automatically applies if ownership or control changes. [112] SA Power Networks has separate deemed contracts for small retail customers and large retail customers.[113] Each includes the requirement for customers to comply with energy laws, and SA Power Networks' reasonable requirements made under those laws, including its Service and Installation Rules (SIR).[114]

In its submission to the Issues Paper, SA Power Networks raised three concerns relating to provisions for embedded generation connection agreements.

#### 5.2.2.1 Terms and conditions of deemed standard connection contracts

First, SA Power Networks noted concern that the full range of terms and conditions it uses in its initial connection of embedded generation cannot be imposed through deemed standard connection contracts, because they are not required by energy laws. These include, for example, SA Power Networks' provisions for fixed or flexible export limits. SA Power Networks' current practice is to manage this by approaching new customers to negotiate different terms and conditions.

SA Power Networks has requested that the Code refer to these further terms and conditions, so they become jurisdictional legislative requirements and so may be included in deemed contracts.[115] The Commission considers that the matter of whether further technical provisions for the connection and operation of embedded generation should apply in South Australia is best addressed by the Technical Regulator.

Second, SA Power Networks noted concern that the deemed standard connection contracts do not require customers with embedded generation to comply with SA Power Networks' Technical Standards. SA Power Networks requested the Code refer to Technical Standards so they become jurisdictional legislative requirements and so may be included in deemed contracts:

> *We request that the Code include reference to our technical standards or include standards and operational requirements on DER that is connected under Chapter 5A of the Rules. This would allow SA Power Networks to require ongoing compliance with its technical standards … and enable SA Power Networks to undertake measures such as Enhanced Voltage Management and dynamic*

[111] SA Power Networks, Model Standing Offer 3602
[112] Deemed Standard Connection Contract, Schedule 2 of the National Energy Retail Rules, clause 6.6(a), also see National Energy Retail Rule 147A(1).
[113] SA Power Networks, Deemed Standard Connection Contract 3603 and Deemed Standard Connection Contract 3604
[114] In clauses 6.3
[115] SA Power Networks submission to Issues Paper, p. 19

> *export limits where necessary for network stability and continue to manage the quality of supply and other effects of distributed energy resources on our distribution system.*[116]

In May 2022, the Technical Regulator approved changes to SA Power Networks' SIR, which elevated the status of the associated Technical Standards. SA Power Networks' Technical Standards are now Technical Installation Rules (**TIR**) and are enforceable under the Electricity Regulations. Now, compliance with the Technical Standards is a requirement of South Australian energy law.

The SIR apply to new installations, alterations and repairs or additions to existing installations that are connected to the distribution network (see SIR 1.2). The SIR also provide a framework for ongoing compliance (see SIR 9.2.5), although demonstration of ongoing compliance is not explicitly required for embedded generators with capacity less than 30kVA connected to the low voltage network.[117]

The Commission considers that matters relating to ongoing compliance with Technical Standards, whether and how existing embedded generators may need to respond as Technical Standards change over time, and whether further technical provisions for the connection and operation of embedded generation are needed (for example, to enable enhanced voltage management or dynamic export limits), are best addressed by the Technical Regulator.

In its submission to the draft decision, SA Power Networks did not comment further on this matter.

#### 5.2.2.2 Continuity of connection agreements – gap in regulatory framework

Third, SA Power Networks noted that, for a small group of generators, there is no regulatory requirement or provision for a connection agreement to apply if ownership or control changes.

This group is comprised of embedded generators that are not required to register with AEMO (primarily those with capacity less than 5MW) and are not customers[118] (that is, do not purchase electricity through a retailer). SA Power Networks has indicated there are up to 50 embedded generators in this group, including generators with installations such as PV farms.

Without a connection agreement in place, operation of these generators may pose a risk to system security, as all necessary obligations for secure network connection and operation may not be created or properly understood.

The Office of the Technical Regulator (**OTR**) has advised that, in the absence of a connection agreement with SA Power Networks, embedded generators have a responsibility to ensure they are operated and maintained in compliance with technical and safety requirements imposed under the Electricity Regulations,[119] which since May 2022 have included SA Power Networks' suite of technical standards for embedded generation. Installations that do not comply may be disconnected by an authorised officer.[120]

Until recently, the Commission's licensing regime partially filled this gap in the regulatory framework. Generation licences issued by the Commission require that a connection agreement is in place.

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116 SA Power Networks submission to Issues Paper, p. 13

117 Currently, TS132 and TS133 (at clause 7.3) require embedded generators to demonstrate ongoing compliance with the SIR and TS; demonstration of ongoing compliance is not explicitly required in TS129 (which applies to embedded generators with capacity less than 30kVA connected to the low voltage network).

118 In the National Energy Retail Rules, a customer is a person who buys or wants to buy energy from a retailer (see National Energy Retail Rules Schedule 1 and the National Energy Retail Law (South Australia) Act 2011 s. 5). This is a subset of the group of embedded generation operators considered to be retail customers for the purpose of initial connection in Chapter 5A.

119 Electricity Act s. 60, Electricity Regulations s. 55(1)(b)

120 Electricity Act s. 70(1)

Transfer of a generation licence to a new licensee is contingent on a connection agreement being made (either a new connection agreement, or novation of an existing connection agreement).

The licensing framework through which the Commission can impose conditions on some generators is under review.[121] While that review is being conducted, a temporary class exemption is in place for generators with capacity of 5MW or less that do not have an existing license.[122] Generators with an existing license may surrender their licence and rely on the exemption.

Until the temporary exemption of sub-5MW generators from licensing, the statutory exemption threshold meant generators with capacity of more than 100 kVA and selling electricity had to maintain a connection agreement. This covered all generators with capacity of more than 100kVA, including those not required to register with AEMO and those that are not customers.

Currently, SA Power Networks manages this gap by approaching new owners or operators to enter into a connection agreement, as it becomes aware that ownership has changed. SA Power Networks may become aware control has changed as a result of complaints made by other customers.

In its submission to the Issues Paper, SA Power Networks suggested that the Code be used to require all embedded generators to maintain a connection agreement: *'This will address the regulatory gap and ensure there is a contractual framework for all connections (both new and ongoing) enabling the ongoing management of safety and technical issues'.* [123]

In its submission to the draft decision, SA Power Networks reiterated the importance of embedded generators having a connection agreement and suggested that generators exempt from licensing be required to establish and maintain a connection agreement.[124]

The Commission has made the final decision not to use the Code to require all embedded generators to maintain a connection agreement.

Continuity of connection agreements would most logically and appropriately be addressed in the national framework. The Commission will raise the matter of addressing this gap in the national framework with the relevant parties.

In the absence of changes to the national framework:

- SA Power Networks may continue to manage this gap by identifying generators in this group, and approaching generators to enter into connection agreements (if one is not in place) or request notification of any upcoming change in ownership or control.
- SA Power Networks may, in consultation with the AER, consider if new connection agreements made with generators in this group may require notification of any upcoming change in ownership or control.
- The DEM may consider the need for this group of generators to provide notification of any upcoming change in ownership or control as part of its Review of the South Australian Electricity Licensing Framework.

[121] Department for Energy and Mining, Review of the South Australian Electricity Licensing Framework, 2022
[122] Essential Services Commission of South Australia, Electricity generation licence exemption – Virtual Power Plant operations, electric vehicle charging operators, and sub-5MW operators, 2021
[123] SA Power Networks submission to Issues Paper, p. 17, see also suggested clauses on p.18
[124] SA Power Networks submission to Draft Decision, p. 4

# 6 Street light repair obligations

SA Power Networks is responsible for operating around 240,000 street lights in South Australia, for 69 public lighting customers including local councils and the South Australian Department for Infrastructure and Transport.

The Commission has a limited role in the regulation of street lights in South Australia. That role is limited to the two Code provisions that apply to SA Power Networks' street light operations:

- a street light repair service standard. SA Power Networks must use its best endeavours to repair street light faults affecting lights for which it is responsible within five business days in metropolitan Adelaide and some regional towns, and within ten business days elsewhere,[125] and
- a street light repair Guaranteed Service Level (**GSL**) payment. SA Power Networks must make a GSL payment to the first person to report the street light fault if it does not repair the fault within these timeframes. A payment of $25 applies for each subsequent five- or 10-day period in which the fault is not repaired.[126]

A small number of street lights in South Australia are operated and maintained directly by local councils or the State Government; the Code provisions do not apply to those arrangements.

## 6.1 Street light repair service standard

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| The final decision is to remove the street light repair service standard from the Code. The service standard is no longer required, because the Public Lighting Service Framework contains a street light repair service level and provides a structure for SA Power Networks to deliver and be held accountable for timely street light repairs. The framework will be supported by transitional street light annual performance reporting requirements that the Commission will apply in the 2025 – 2030 period. |

The final decision on the street light repair service standard is the same as the draft decision. In response to concerns raised in consultation, the final decision expands the scope of the transitional street light annual performance reporting requirements that will apply in the 2025 – 2030 period (see section 6.3). The expanded scope includes a requirement for SA Power Networks to report directly to its public lighting customers.

### 6.1.1 Submissions to draft decision

In its submission to the draft decision, SA Power Networks considered that a timely street light repair service standard should be retained in the Code, because public lighting customers have expressed concern that current reporting on fault reporting and repairs is not transparent.[127] SA Power Networks acknowledges this concern and has expressed commitment to implementing new operational performance reporting before the end of the 2020 – 2025 period.[128]

In his short submission to the draft decision, Mr Arthur Marsh raised concern about the timely repair of street lights which are not the responsibility of SA Power Networks. He is concerned that there is no framework for other street light operators to be held accountable for timely repairs.[129]

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125 Clause 2.3.1(b)(i)
126 Clause 2.3.1(b)(ii)
127 SA Power Networks, submission to Draft Decision, p. 11
128 SA Power Networks, submission to Draft Decision, p. 11
129 Mr Arthur Marsh, submission to Draft Decision

In consultation on the draft decision, the Commission held discussions with public lighting stakeholders that did not make formal written submissions to the review. Concerns raised included:

- lack of regular, audited reporting by SA Power Networks to public lighting customers on all aspects of service delivery (including but not limited to timely street light repair)
- uncertainty about the actual number of street light faults, and the proportion of actual faults represented in current reporting
- quality of public lighting asset data, and data sharing between SA Power Networks and public lighting customers; this affects correct identification of who is responsible for individual lights that need repair, and
- that members of public who report street light outages do not receive information about whether outages have been resolved, reasons for delays, or who is responsible for the relevant light.

The Commission is limited to considering street light repair services provided by SA Power Networks. The legislative framework does not provide for Code provisions to be made for street lights operated and maintained directly by local councils or the State Government.

The Commission's final decision is to remove the street light repair service standard. Issues raised in consultation are best addressed by expanding the scope of the transitional street light performance annual reporting requirements that will apply in the 2025 – 2030 period (as set out in section 6.3).

### 6.1.2 Discussion

Until recently, transparency around public lighting services provided by SA Power Networks has been limited. Most aspects of public lighting services have been addressed in commercial contracts between SA Power Networks and its public lighting customers. Only the street light repair service standard has been set transparently (in the Code) and has required public performance reporting.

Since the Public Lighting Service Framework (the **framework**) was published in 2020, transparency has improved, and the role of the AER in relation to public lighting services has expanded.[130,131]

The framework is the product of consultation between SA Power Networks and its public lighting customers through the Public Lighting Working Group (**PLWG**). It is a public document that contains a suite of service levels including for the timely repair of street light faults and also, for example, requirements for maintaining light output, timeframes for the bulk changeover of street lights, roll out of Light Emitting Diode (**LED**) lighting, and street light cleaning. It provides for SA Power Networks to deliver regular operational performance reports to its public lighting customers.

The framework is not a formal regulatory instrument. Neither the Commission nor the AER has a formal role monitoring or ensuring compliance with the framework.

[130] The Australian Energy Regulator reclassified public lighting services as an Alternative Control Service for the 2020 – 2025 period, and therefore established price caps for public lighting services. Service levels are one input in establishing price caps. See: Australian Energy Regulator, July 2018, Final framework and approach - SA Power Networks regulatory control period commencing 1 July 2020. In discussions with the Australian Energy Regulator, it has indicated it will again classify public lighting services as an Alternative Control Service for the 2025 – 2030 period.

[131] SA Power Networks, Public lighting service framework, February 2020

However, the framework is an important part of the regulatory setting; it clearly defines service levels and is evidence that public lighting customers support those service levels. This is a necessary input for the AER in setting public lighting price caps.[132]

The framework and its service levels form conditions of the standard contract between SA Power Networks and its customers for public lighting service provision (the Alternative Control Services Tariff Agreement).

The framework provides a basis for direct negotiation about public lighting services and their associated public benefits, and for public lighting customers to hold SA Power Networks accountable. The purpose of the framework is to promote positive outcomes for public lighting customers, and public lighting consumers (residents, businesses and road users).

In its submission to the Issues Paper, SA Power Networks expressed a preference for the Commission to continue its role in monitoring the timely repair of street lights, citing reservations about agreeing service levels within the PLWG.[133] In the draft decision, the Commission acknowledged that there will be a diversity of views on service levels within the PLWG, and did not consider this detrimental to using the group as the forum to establish service levels.

In its submission to the draft decision, SA Power Networks considered that a timely street light repair service standard should be retained in the Code, because public lighting customers have expressed concern that current reporting on fault reporting and repairs is not transparent.[134]

In consultation on the draft decision, other stakeholders raised concerns about lack of regular, audited reporting by SA Power Networks to public lighting customers on all aspects of service delivery (not just timely street light repair). These views contrasted with the Commission's understanding at the time of the draft decision, which was that operational reporting to public lighting customers was satisfactory.

The Commission acknowledges the concerns raised regarding reporting. Reporting is vital to ensure transparency and accountability for public lighting services. The Commission's view is that this is best addressed by expanding the transitional street light annual performance reporting requirements that will apply in 2025 – 2030 (see section 6.3), rather than retaining the street light repair service standard.

The final decision is the same as the draft decision: the street light repair service standard is no longer required. In making this final decision, the Commission has considered:

- that the interests of public lighting customers (local councils and the State Government) are closely aligned with those of public lighting consumers, meaning consumers' interests are represented in the framework
- that there have been minimal complaints to the Energy and Water Ombudsman of South Australia (**EWOSA**) about public lighting outcomes from either public lighting customers or consumers (around six per year between 2017-18 and 2021-22, all from consumers, with the majority relating to the GSL payment)
- that the framework makes provision for disputes that cannot be resolved to be referred to EWOSA, and that the Alternative Control Services Tariff Agreement makes further provision for disputes to be resolved through mediation or arbitration
- that the street light repair service level in the framework requires better outcomes than the service standard in the Code:

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132 In discussions with the Australian Energy Regulator, it has indicated it relies on the framework as evidence that customers support service levels in making its decision on price caps.

133 SA Power Networks submission to Issues Paper, p. 7

134 SA Power Networks submission to Draft Decision, p. 11

  - the framework and the Code have the same timeframes for street light repair (five days in metropolitan Adelaide and some regional towns, and ten days elsewhere)
  - the framework sets a target for meeting timeframes (currently 98 percent of repairs within timeframes), which is more onerous that the Code's 'best endeavours' obligation
  - the 98 percent target reflects recent historical performance (in the ten years to 2021-22, 93 percent of repairs have been made within timeframes in metropolitan Adelaide and some regional towns and 99 percent of repairs have been made within timeframes elsewhere)
- that the framework has been in use by SA Power Networks and public lighting customers since 1 July 2020; there has been time for testing, and improvements can be made in its review ahead of the 2025 – 2030 period, and
- that concerns about operational reporting can be addressed through expanded transitional street light annual performance reporting requirements in 2025 – 2030, which will support SA Power Networks' development of its reporting to public lighting customers.

## 6.2 Street light repair GSL payment

> The final decision is to remove the street light repair GSL payment from the Code, on the basis that its benefit is limited to being an uncertain incentive for people to report street light outages.
>
> There is a low, manageable risk that there will be fewer reports of street light outages without the GSL payment. As a transitional measure, annual reporting on street light outages and repairs will be retained during the 2025 – 2030 period to monitor the impact of these changes.

The final decision on the street light repair GSL payment is the same as the draft decision. In response to concerns raised in consultation, the final decision expands the scope of the transitional street light annual performance reporting requirements that will apply in the 2025 – 2030 period (see section 6.3).

SA Power Networks is responsible for ensuring it has sufficient information from the field to meet its contractual obligations to public lighting customers and will need to consider whether a response is needed, and the nature of that response, if there are fewer reports of street light outages following removal of the GSL payment.

### 6.2.1 Submissions to draft decision

In their submissions to the draft decision, SA Power Networks and SACOSS supported the draft decision to remove the GSL payment.[135]

However, as noted in SA Power Networks' submission, there are mixed views amongst public lighting customers about whether the GSL payment should be removed. This was also clear in discussions that the Commission held with public lighting stakeholders, noting that they did not make formal written submissions.

Some public lighting stakeholders support the payment being removed. Others consider that there would be fewer reports of street light outages without a GSL payment or are unsure about the impact of removing the GSL payment on reporting.

[135] SA Power Networks submission to Draft Decision, p. 11. South Australian Council of Social Service, submission to Draft Decision, p. 5.

### 6.2.2 Discussion

Currently, SA Power Networks must make a GSL payment to the first person to report a street light fault if it is not repaired within five business days in metropolitan Adelaide and some regional towns, or ten business days elsewhere; a payment of $25 applies for each subsequent five- or 10-day period in which the fault is not repaired.[136]

The final decision is to remove the street light repair GSL payment from the Code. In making this final decision, the Commission has reviewed the cost of the payment, the benefits attributed to it over time, and whether these are being delivered. This is set out in detail below.

Based on evidence presented in this section, the Commission considers that the payment delivers limited benefit:

- there is no contemporary analysis of the most efficient way to get information about street light outages from the field
- the payment is an uncertain incentive for people to report street light outages – around 94 percent of people who report a street light outage will not receive a payment, and people are more likely to report street light outages because they are concerned about safety
- managing the cost of the payment is a limited incentive to SA Power Networks, because its ability to control costs is constrained – payments apply to a minority of typically complex faults, and
- the payment is not designed as a service gesture, in that it is only made to the first person that reports the outage.

There is a low risk that in removing the payment SA Power Networks will not get the information it needs to identify all street light outages. In that case, its obligation to repair street light faults within timeframes as set out in the framework, and the broader obligations in the framework which include an obligation to maintain light output, will provide an incentive for it to develop a solution.

The Commission will require reporting through the next period to monitor this risk and promote accountability for SA Power Networks' obligations under the framework. Reporting requirements are described in section 6.3.

### 6.2.3 Cost of the street light repair GSL payment

Across the ten years to 2021-22, an average of 29,690 street light outages were reported to SA Power Networks each year. On average, 5.9 percent (1,760) of these outages were not repaired within timeframes and attracted a GSL payment with an average value of just over $100.

The average total annual cost of the street light GSL payment across this period was $190,000, not including indirect costs such as those associated with administration and communication.

The costs of the GSL payment are incorporated into the tariffs SA Power Networks charges its public lighting customers. End-use consumers contribute to the costs of public lighting only indirectly (for example, through rates or taxes). Yearly variation in the costs of the payment is borne by SA Power Networks.

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[136] Clause 2.3.1(b)(ii)

### 6.2.4 A cost-effective alternative to distributor night patrols

Initially, this GSL payment was included in the Code because it was considered a cost-effective alternative to the distributor patrolling the streets at night to identify outages.[137]

Since then, the outage rate has declined, and there has become less need for information from the field to identify outages.[138] This is because of changed practices in maintaining street lighting, particularly more extensive use of bulk lamp changes, and reliance on inspection and replacement regimes for LED lights (which dim over time instead of failing suddenly). Practices will continue to change with the ongoing roll out of LED lighting, and other improvements in street lighting technology.

For the time being, information from the field about outages is still needed. SA Power Networks relies on public reports to get that information. Alternatives include distributor night patrols and use of smart lighting technology to automatically generate outage notices.

There is no contemporary analysis of the most efficient way of obtaining information from the field. As the operator of public lighting, SA Power Networks is best placed to identify which method is most efficient. This is discussed further in the following section.

### 6.2.5 An incentive for people to report outages

When the GSL payment was first included in the Code, it was considered to provide an incentive for people to report street light outages.

While there is a view that the payment encourages people to report street light outages (as illustrated by the submission to the Issues Paper from Mr Arthur Marsh[139]), current evidence suggests that the GSL payment provides only an uncertain incentive.

Over the last ten years, GSL payments have been made in relation to 5.9 percent of reported outages. The current situation is that most people who report a street light outage will not receive a payment.

Members of the public are likely to report outages without an incentive because they are concerned about safety and are able to do so with increasing ease. This is demonstrated by:

- the case of TasNetworks (the Tasmanian Distribution Network Service Provider), which removed its street light repair GSL payment in 2017 without impact to reporting rates (see case study in Box 3).
- use of Apps such as the Local Government Association's (LGA) My Local Services and the third-party App Snap Send Solve.[140]

However, the possibility remains that the payment does incentivise some reports, and there is a low risk that in removing it SA Power Networks will not get the information it needs to identify all street light outages.

137 Essential Services Commission of South Australia, 2005 – 2010 Electricity Distribution Price Determination Part A: Statement of Reasons, p. 51, Essential Service Commission of South Australia, SA Power Networks Jurisdictional Service Standards for the 2015 – 2020 Regulatory Period Draft Decision, p. 34

138 The declining outage rate is demonstrated in the number of street light outages reported by the public. The average of street light outages reported by the public has fallen from 40,662 in the five years to 2004-05 to 27,753 in the five years to 2021-22.

139 Mr Arthur Marsh, Submission to Issues Paper

140 In 2020-21, members of the public reported 9,500 issues to local councils using the My Local Services app in South Australia. In 2020, members of the public reported 13,000 issues to relevant organisations through the Send Snap Solve app in South Australia. The number of street light outages reported through Snap Send Solve is small but increasing (from 98 in 2019 to 207 in 2020), see South Australia - Snap Send Solve.

If, after removal of the GSL payment, SA Power Networks is not receiving sufficient reports, it will have an incentive to develop a solution. That incentive is its obligation to repair street light faults within timeframes as set out in the framework, and the broader obligations in the framework which include an obligation to maintain light output, which form conditions of SA Power Networks' contracts with its customers.

In this scenario, SA Power Networks would need to identify the most efficient way to get information from the field (whether by using night patrols, increasing the roll out of smart lighting technology to automatically generate outage notices, or by introducing a financial reporting incentive).

SA Power Networks' submission to the draft decision suggested that it interpreted this part of the draft decision to mean that the Commission may introduce a GSL payment mid-period if there is a significant drop in street light outage reports.[141]

This is not the Commission's intention. It would be SA Power Networks' responsibility to manage any drop in street light outage reports, to ensure it has sufficient information from the field to meet its contractual obligations to public lighting customers. AER staff have indicated that if SA Power Networks faced an associated cost increase in delivering street light services, this could be incorporated into prices mid-period.

The Commission will require reporting through the next period to monitor this risk and promote accountability for SA Power Networks' obligations under the framework. Reporting requirements are described in section 6.3.

### 6.2.6 An incentive for SA Power Networks to make repairs on time

Although costs of the GSL payment are incorporated into the tariffs SA Power Networks charges public lighting customers which are set for each five-year regulatory period, SA Power Networks is affected by annual cost variation.

Managing that annual cost variation provides a limited incentive to SA Power Networks. In the context of SA Power Networks' overall expenditure, the potential savings are low. Further, SA Power Networks' ability to constrain GSL payment costs is limited. GSL payments typically apply to a minority of street light faults, often where repairs are complex and/or SA Power Networks' control is limited due to issues like road access issues or parts availability.

This is reflected by the position put in SA Power Networks' submissions to the review that, if the GSL payment is to be retained, it should be revised to remove the recurring element, establish a separate timeframe for complex faults (such as cable faults), and limit payments to the person whose premises are adjacent to the street light.[142]

However, SA Power Networks uses the number of GSL payments made as an internal performance target. In that sense, the GSL payment acts as an incentive to manage repairs so they are made on time. This benefit could be equally provided by monitoring and setting a target for repairs made within timeframes, instead of a target for the number of GSL payments.

[141] SA Power Networks submission to Draft Decision, p. 13.

[142] SA Power Networks submission to Issues Paper, p. 33; SA Power Networks submission to Draft Decision, pp. 11-13.

### 6.2.7 A service gesture to road users

In general, GSL payments act as a gesture to acknowledge instances where a consumer receives service that is below expectations.

The street light repair GSL payment is not designed as a service gesture, in that it is only made to the first person that reports the outage. That person is likely to be one road user of many and may not be the person most affected by the outage. Previous research by the Commission has shown that such gestures are not universally valued by customers when they understand that the costs are incorporated into the overall costs of essential services.[143]

[143] Essential Services Commission of South Australia, 2019, SA Power Networks Reliability Standards review – final decision, p. 40

**Box 3: TasNetworks street light repair GSL payment**

TasNetworks' street light repair GSL payment ceased in 2017. It had been established through the TasNetworks Customer Charter, approved by the jurisdictional regulator, the Office of the Tasmanian Economic Regulator (OTTER). It applied to street lights operated by TasNetworks, of which there were around 36,000 in 2017-18.

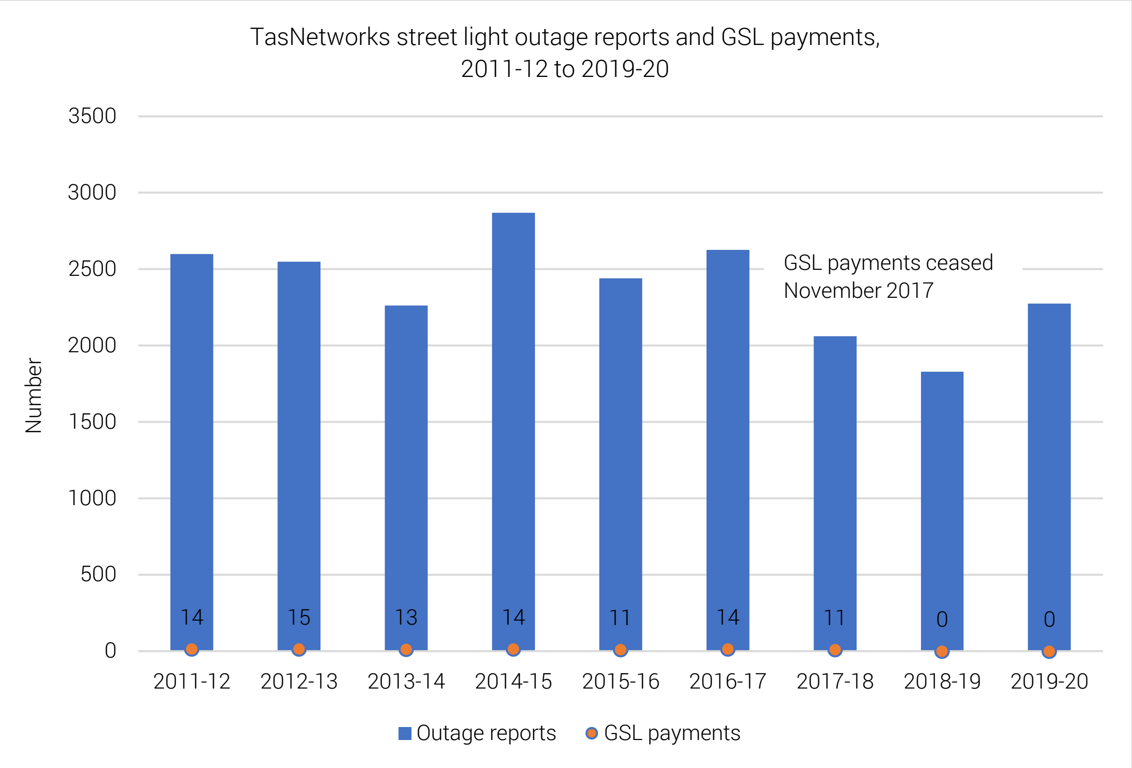
The $30 one-off payment applied if a street light outage was not repaired within seven days. It was made to the first customer to report the outage, where the outage occurred on that customer's street. Unlike the SA Power Networks payment, which is made automatically, customers had to apply to TasNetworks to claim the payment.

Prior to the payment being discontinued, its value was progressively reduced from $140 in 2011-12 to $30 from 2014-15, reflecting feedback from TasNetworks' customer engagement.

In 2018-19, the first full year after payments ceased, the number of outages reported fell slightly, but increased again in 2019-20. OTTER considers that cessation of the payment did not have a significant impact on the number of outages being reported.

During the time the payment existed very few customers submitted claims. This suggests that customers made reports because they wanted the lights to be repaired, rather than because they were motivated by the possibility of a financial reward.

After the payment ceased, OTTER required that TasNetworks continue reporting on street light outage reports and repairs for two years. TasNetworks no longer reports on those matters to OTTER, but does report street light outage data to the AER.




Data sources: Energy in Tasmania workbooks 2019-20 and 2015-16; Energy in Tasmania report 2015-16 (Table 5.16); Energy in Tasmania report 2019-20 (Table 8.16); discussions with OTTER and TasNetworks.

## 6.3 Street light repair performance reporting

The final decision is that transitional street light performance reporting requirements will apply in the 2025 – 2030 period. Under these arrangements, SA Power Networks will be required to report both to the Commission and directly to its public lighting customers. The manner, form and content of reporting requirements, which will be subject to further consultation, will be set out in Electricity Industry Guideline No. 1.

The final decision is that transitional street light performance reporting requirements will apply in the 2025 – 2030 period. This will promote accountability of SA Power Networks to its public lighting customers and ensure oversight by the Commission of the timely repair of street light faults.

Under these arrangements, SA Power Networks will be required to report annually to both to the Commission and directly to its public lighting customers. This will support SA Power Networks' development of its reporting to public lighting customers, which is an obligation of the Public Lighting Service Framework.[144]

As shown in the revised version of the Code that accompanies this final decision, the relevant changes to the Code are addition of a new clause 2.7.6 and a definition of public lighting customer.

The reporting requirements will be set out in Electricity Industry Guideline No. 1 and be subject to further consultation. That consultation will be with public lighting customers and SA Power Networks and occur in the second half of 2024, ahead of publication of draft amendments to Electricity Industry Guideline No. 1 in January 2025.

The content of reporting requirements will include the measures SA Power Networks currently reports on in Electricity Industry Guideline No. 1:

- total number of street lights for which SA Power Networks is responsible
- total number of street light faults reported for which SA Power Networks is responsible, and
- average number of business days to repair street light faults from the date at which the fault came to SA Power Networks' attention. [145]

SA Power Networks reports against these measures separately for metropolitan Adelaide and some regional towns, and for places outside that area.[146]

As foreshadowed in the draft decision,[147] additional reporting requirements will (subject to further consultation) include:

- metrics in the framework relevant to the timely repair of street light faults (selected from Attachment A – target levels of service and Attachment B – Service driven pricing parameters)
- description of methods used to obtain information about street light outages, including but not limited to avenues for public reporting (noting the need to understand whether public reporting gives sufficient information to maintain public lighting output)

[144] SA Power Networks, Public lighting service framework, February 2020, p. 21
[145] At OP 3.1.
[146] These are specified in the Code at clause 2.3.1(b)(i)
[147] Essential Services Commission of South Australia, Electricity Distribution Code review Draft Decision, 2023, p. 50

- analysis of complaints received from public lighting customers and consumers, and
- other requirements identified through consultation.

In establishing transitional street light performance reporting requirements, the Commission will have regard to aligning with the AER's reporting requirements,[148] and SA Power Networks' plans for developing reporting to its public lighting customers.

These requirements will be a transitional measure. Subject to the Commission's satisfaction with SA Power Networks direct reporting to public lighting customers, they may not be required beyond the 2025 – 2030 period.

[148] See: Australian Energy Regulator, SA Power Networks Network information – RIN responses, Annual reporting RIN templates – 3.6.7.2 – Timely repair of faulty street lights

# 7 Next steps

The Commission would be pleased to meet with stakeholders, either individually or with representative organisations, to discuss this final decision. If you or your organisation wish to meet with the Commission, please use the contact details on the inside cover of this report.

The final decision will result in changes to SA Power Networks' regulatory reporting requirements, set out in Electricity Industry Guideline No. 1. The Commission plans to publish draft changes to Electricity Industry Guideline No. 1, for consultation, in January 2025, followed by finalised changes in June 2025.

The Commission will continue to monitor national and State reviews and regulatory reform regarding distributed energy resources and whether their outcomes adequately project the long-term interests of South Australian consumers.

Key dates are set out in Table 5 below.

Table 5: Key dates

| Date | Milestone |
|---|---|
| June 2024 | Consultation on transitional street light performance reporting requirements |
| January 2025 | Publication of draft amendments to Electricity Industry Guideline No. 1 for public consultation<br><br>Publication of performance targets for revised telephone responsiveness and first call resolution service standards for public consultation |
| April 2025 | Publication of final Electricity Industry Guideline No. 1 (G1/14) |
| 1 July 2025 | Commencement of revised Electricity Distribution Code (EDC/14) |

# Appendix 1: Minimum network reliability standards – supporting information

### Historical approach to setting targets

The minimum network reliability standards set by the Commission require that SA Power Networks use its best endeavours to achieve a series of minimum network reliability performance targets.

Historically, the Commission has established minimum network performance targets using an average of performance over the longest possible time period. The data used to set targets for each regulatory period is described in Table 6.

Table 6: Data used to set performance targets for each regulatory period

| Regulatory period | Data used | Detail |
|---|---|---|
| 1999 – 2005 | 1999 reliability levels - distributor supplied data | Targets set by the Electricity Reform and Sales Unit in the South Australian government. |
| 2005 – 2010 | four years of data (2000-01 – 2003-04)[149] | Four years of data available following the first post-privatisation improvements to data accuracy. |
| 2010 – 2015 | four years of data (2005-06 – 2008-09)[150] | Four years of data available following the introduction of the distributor's Outage Management System (OMS) in 2005-06 which for the first time measured, rather than modelled, low voltage outages. |
| 2015 – 2020 | five years of data (2009-10 – 2013-14) | Five years of data available following improvements to the OMS, the OMS was significantly improved between 2005-06 and 2008-09. |
| 2020 – 2025 | 10 years of data (2009-10 – 2018-19) | Ten years of accurate, consistent data available following improvements to the OMS. |

Using this approach, the Commission has sought to reflect changes in reliability made over time (to ensure targets remain consistent with consumer expectations), and smooth the impact of one-off events.

In making this final decision, the Commission considered whether to use this historical approach. Network performance data is currently available for the 13 years from 2009-10 to 2021-22, and 15 years' data will be available before the start of the next regulatory period.

One consideration is whether using 15 years of data would better smooth the impact of one-off events. The Commission considers that while using 15 years of data would capture some further variation, it is not necessary because the broader framework excludes outages that occur on Major Event Days (MEDs) and provides that standards may be met using best endeavours assessments where targets are not met.

[149] Essential Services Commission of South Australia, 2005-2010 Electricity Distribution Price Determination, Part A – Statement of Reasons, April 2005, Table 3.1 and 3.2, pp. 36-37

[150] Essential Services of South Australia, South Australian Electricity Distribution Service Standards 2010 – 2015, Final Decision, p. 63

As discussed in section 4.1, the Commission considers that it is not necessary to reset performance targets using the historical approach for the 2025 – 2030 period. Targets in the current Code are sufficient to maintain reliability and meet legislative requirements.

**Legislative requirements for minimum standards of service**

The Commission must satisfy legislative requirements in establishing minimum network reliability standards.

Those requirements are set out in the *Electricity Act 1996* (**Electricity Act**), which requires the Commission to impose minimum standards of service equivalent to those that existed before the privatisation of distribution services in South Australia. Standards must be equivalent to the levels of service that existed in the year prior to 11 October 1999.

The Electricity Act further requires the Commission to take into account relevant national benchmarks in establishing minimum standards of service, and to require SA Power Networks to monitor and report on compliance with those standards.

The Electricity Act makes these requirements in section 23(1)(n)(v). It sets out that 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'.*

Section 23(1)(n)(v) commenced through the Electricity (Miscellaneous) Amendment Act 1999, which was proclaimed on 30 September 1999 and took affect from 11 October 1999.[151, 152]

The Commission considers network reliability in 2005-06 as an indicator for the standards of service that existed during the year prior to 11 October 1999 (as shown in Table 7), notwithstanding that issues with data accuracy and consistency persisted until 2008-09 (as described in Table 6). More significant issues with data quality mean that data for years prior to 2005-06 is not suitable for comparison with more recent performance.

Table 7: Baseline performance data - standards of service prevailing in 2005-06

| Region | USAIDIn | USAIFIn |
|---|---|---|
| CBD feeders | 24 | 0.22 |
| Urban feeders | 147 | 1.66 |
| Rural short feeders | 187 | 2.01 |
| Rural long feeders | 335 | 2.42 |

Data source: SA Power Networks, data prepared for SA Power Networks Annual Reliability Performance Reports

It is important to note that, while the Commission has a legislative obligation to consider reliability outcomes that prevailed in the year before privatisation, performance in a single year does not

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

necessarily represent underlying reliability. Single-year performance may be impacted by one-off events that are outside the control of the distributor. Underlying reliability is best represented as the average of long-term performance.

**Restoration of supply – historical performance data**

Average restoration of supply outcomes for 13-year period to 30 June 2022 have been slightly better than the performance targets in the Code for urban and rural short feeders. These differences are shown below in Table 8.

Table 8: Restoration of supply targets in 2020 – 2025, and average performance over 13 years to 30 June 2022

| | | | CBD Feeders | Urban Feeders | Rural Short Feeders | Rural Long Feeders |
|---|---|---|---|---|---|---|
| Percentage of total customers in each feeder category per annum | Interruption equal to or greater than 1 hour | 2020-25 target | 11 | | | |
| | | 13-year mean | 11 | | | |
| | Interruption longer than 2 hours | 2020-25 target | 4 | 27 | | |
| | | 13-year mean | 4 | 26 | | |
| | Interruption longer than 3 hours | 2020-25 target | | 11 | 27 | |
| | | 13-year mean | | 11 | 26 | |
| | Interruption longer than 4 hours | 2020-25 target | | | | 30 |
| | | 13-year mean | | | | 30 |
| | Interruption longer than 5 hours | 2020-25 target | | | 8 | |
| | | 13-year mean | | | 8 | |
| | Interruption longer than 7 hours | 2020-25 target | | | | 10 |
| | | 13-year mean | | | | 10 |

# Appendix 2: Embedded generation provisions – supporting information

| Item number | Clause (EDC 13.1 numbering shown) | Discussion | Final decision |
|---|---|---|---|
| 1 | 1.5 Definitions<br><br>Australian Standard<br><br>electricity distribution determination<br><br>embedded generator<br><br>embedded generating unit<br><br>good electricity industry practice<br><br>large embedded generator<br><br>small embedded generator | As a result of the changes to this Chapter, these definitions are no longer required. | These definitions will be removed. |
| 2 | 1.5.2 References to **Australian Standards** are references to standards existing from time to time as amended, or where they are superseded, their replacements. | Australian Standards are only referred to in clause 3.17. The proposal is to remove that clause, so clause 1.5.2 is also no longer required. | Clause 1.5.2 will be removed. |
| 3 | 3.9 Coordination of Large Embedded Generating Units<br><br>3.9.1 **Large embedded generators** must comply with the following requirements:<br><br>(a) the **embedded generating unit** must be synchronised to the **distribution network** | Clause 3.9.1(a) is duplicated by the synchronisation requirements set out in TS132 (4.9.4) and TS133 (4.9.2.6). | Clause 3.9 .1(a) will be removed. |

| Item number | Clause (EDC 13.1 numbering shown) | Discussion | Final decision |
|---|---|---|---|
| 4 | (b) the **embedded generating unit's** real and reactive power output or voltage output must be automatically controlled within limits agreed with the **distributor**. A nominal full load power factor of 0.8 lagging must be provided | Clause 3.9.1(b) is inconsistent with the requirements for automatic real and reactive power control made in TS132 and TS133 (4.6.1 and 4.6.2), which are more detailed and nuanced than the requirements of the clause – see also SIR (6.5.3 and 10.3.2), TS132 (4.12.3) and TS133 (4.12.2). | Clause 3.9 .1(b) will be removed. |
| 5 | (c) the **embedded generator's** voltage and frequency response times must be within the limits specified by the distributor. If the **embedded generator's** frequency rises above or falls below the system frequency for more than the time specified by the **distributor**, it must be disconnected from the **distribution network** | Clause 3.9.1(c) is duplicated by the requirements for voltage and frequency limits, disconnection and response times set out in TS132 and TS133 (4.9.2.1). | Clause 3.9 .1(c) will be removed. |
| 6 | (d) the **embedded generating unit** must be fitted with necessary protection relays, as agreed with the **distributor**, in order to coordinate its ability to isolate itself from the **distribution network** in the event of a fault on either the **distributor's distribution network** or the **embedded generator's** electricity infrastructure | Clause 3.9.1(d) is duplicated by the requirements for protection, disconnection and coordination set out in SIR 5.2.5 (TIR), and TS132 and TS133 (4.9). | Clause 3.9 .1(d) will be removed. |
| 7 | (e) the **embedded generating unit** must be equipped with lockable means of isolation from the **distribution network** | Clause 3.9.1(e) is duplicated in intent by the requirement for lockable means of isolation at the connection point made in TS132 and TS133 (4.7), SIR 5.13.1 (TIR) and SIR 10.4.5 (TIR). | Clause 3.9 .1(e) will be removed. |

| Item number | Clause (EDC 13.1 numbering shown) | Discussion | Final decision |
|---|---|---|---|
| 8 | (f) unless otherwise agreed with the distributor, an **embedded generator** must allow for the **connection** of a communication link between the **embedded generation unit** and the **distributor's** substation to monitor and as necessary trip the generator in an **emergency** | Clause 3.9.1(f) is partially duplicated by the requirements for large embedded generators to have a communication link for monitoring and control made in TS134. SA Power Networks has made an intentional choice that remote tripping capability is only required for large embedded generators that are not inverter-connected, or other embedded generators at its discretion. | Clause 3.9 .1(f) will be removed. |
| 9 | (g) asynchronous **embedded generating units** must be equipped with controlled power factor correction capacitors to support necessary VAR loading requirements, and | Clause 3.9.1(g) is inconsistent with the requirements of TS132 and TS133, which require asynchronous embedded generators to manage Volt-ampere reactive (**VAR**) loading, but do not specify the need for power factor correction capacitors. The clause's requirement for power factor correction capacitors for asynchronous embedded generators is outdated, and the intent of this clause is covered in TS132 and TS133. | Clause 3.9 .1(g) will be removed. |
| 10 | h) any other reasonable requirement of the **distributor.** | SA Power Networks is able to make reasonable requirements of embedded generators in its connection agreements and associated Technical Standards. Therefore retaining a general provision such as that at 3.9.1 (h) is not necessary. | Clause 3.9.1(h) will be removed. |
| 11 | 3.10 Capacity<br><br>3.10 .1 The capacity of **embedded generator**'s plant shall not exceed the capacity of the **distribution network** in terms of:<br><br>(a) its capacity to accept export energy | Clause 3.10.1 (a) is duplicated by the provisions for imposing export limits and defining the technical parameters that determine network capacity in SIR 6.2 (TIR) and TS129 (4.1.5 and 4.2.1), TS132 and TS133 (4.3.1). | Clause 3.10.1 (a) will be removed. |

| Item number | Clause (EDC 13.1 numbering shown) | Discussion | Final decision |
|---|---|---|---|
| 12 | (b) its capacity to provide emergency energy in the event of a generator trip, and | This clause is partially duplicated by NER S5.2.5.12, SIR 6.2.5 (TIR), TS132 and 133 (4.12.1.1), and TS133 (4.16.4).<br>The Commission has reviewed the intent of clause 3.10.1 (b), and considers that it applies to both a trip of the embedded generator to which the clause applies, and to the trip of another embedded generator operating within the distribution network.<br>The meaning of the phrase 'provide emergency energy' may be better expressed as 'supply energy'.<br>In the current Code 'emergency' means 'an emergency due to the actual or imminent occurrence of an event which in any way endangers or threatens to endanger the safety or health of any person, or the maintenance of power system security, in the state of South Australia or which destroys or damages, or threatens to destroy or damage, any property in the state of South Australia.'<br>The Commission considers that the meaning of 'emergency energy' in this clause is narrower. The clause is referring to the ability of the distribution network to continue to supply energy in the event that an embedded generator fails. | Clause 3.10.1 (b) will be removed, the Commission will recommend to the Technical Regulator that it considers whether these matters should be addressed elsewhere in the State regulatory framework. |
| 13 | (c) its fault level. | The intent of clause 3.10.1(c), (and clause 3.15), is duplicated by the fault level requirements set out in TS132 and TS133 (4.3.1 and 4.16.2.1).<br>SA Power Networks does not make the same requirements for some embedded generators covered by TS129 that apply under this clause. This is an intentional choice, and reflects the fact that inverter-connected embedded generators do not contribute as much fault current as synchronous generators. | Clause 3.10.1 (c) will be removed. |

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| 14 | 3.11 Scheduling<br><br>3.11.1 Unless otherwise agreed with the **distributor**, a **large embedded generator** with an **embedded generating unit** over 1MW must advise the **distributor** prior to **connection** or disconnection of the **embedded generating unit**. | This clause is partially duplicated in SA Power Networks' Deemed Standard Connection Contracts 3603 and 3604 (section 6.2) and SIR 5.2, this matter is omitted at TS134 (5.1.3).<br>'Connection' is a defined term in the Code, which 'means to form a physical link to a distribution system'. This clause does not relate to when the embedded generator intends to have output.<br>SA Power Networks has a defined process for connections and disconnections, supported by the national regulatory framework.<br>This clause provides no additional visibility of larger embedded generators and retaining it is not necessary. | Clause 3.11.1 will be removed. |
| 15 | 3.11.2 The rate of change of an **embedded generating unit** over 1MW must be agreed with the **distributor**. | Clause 3.11.2 is duplicated by the requirements for ramp rates for embedded generators over 1MW set out in TS132 and TS133 (4.6, 4.12.1.2). | Clause 3.11.2 will be removed. |
| 16 | 3.12 Minimum requirements for Embedded Generating Units over 1MW<br><br>3.12.1 Unless otherwise agreed with the **distributor**, any **embedded** generating **unit** over 1MW must:<br><br>(a) have an automatic excitation control system for volts and power factor | Clause 3.12.1(a) is inconsistent with the requirements for automatic real and reactive power control made in TS132 and TS133 (4.6.1 and 4.6.2), which are more detailed and nuanced than the requirements of the clause – see also SIR (6.5.3 and 10.3.2), TS132 (4.12.3) and TS133 (4.12.2).<br>This is also noted in the discussion on clause 3.9.1(b). | Clause 3.12.1(a) will be removed. |
| 17 | (b) have a governor control for speed (frequency) and load (MW) control, and | The intent of Clause 3.12.1(b) is duplicated by the requirements for active power control set out in TS132 and TS133 (4.6.2).<br><br>This is also noted in the discussion on clause 3.9.1(b). | Clause 3.12.1(b) will be removed. |

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| 18 | (c) be equipped with protection and auto synchronising equipment as defined by the **distributor.** | Clause 3.12(c) makes similar requirements to clauses 3.9.1(a) and (d).<br><br>Clause 3.12(c) is duplicated by the synchronisation requirements set out in TS132 (4.9.4) and TS133 (4.9.2.6), and the requirements for protection, disconnection and coordination set out in SIR 5.2.5 (TIR), and TS132 and TS133 (4.9). | Clause 3.12.1(c) will be removed. |
| 19 | 3.13 Delivery performance requirements of Embedded Generation Units<br><br>3.13.1 An **embedded generator's** plant shall be able to:<br><br>a) respond safely to network disturbances<br><br>b) shut down safely without external electricity **supply**<br><br>c) restart following loss and restoration of **supply**, and<br><br>d) operate in a stable manner on the **distribution network** during system disturbances. | Clause 3.13.1 is not duplicated by other regulatory instruments. Note that d) is partially duplicated in TS132/33 (at 4.3.1). Further, AS4777.2:2020 (4.7) and TS132/33 (4.9.2) are relevant to c), but the Code requirement is not specifically covered.<br>No other requirements explicitly address the impact of embedded generator performance on the distribution network, only the need for each embedded generator to respond locally.<br>AEMO is currently working on better defining DER impacts on operational stability[153] which may be relevant to consideration of how this matter is addressed in the State framework. | Clause 3.13.1 will be removed, the Commission will recommend to the Technical Regulator that it considers whether these matters should be addressed elsewhere in the State regulatory framework. |

[153] See: AEMO DER operations workstream

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| 20 | 3.14 Voltage Quality<br><br>3.14.1 An **embedded generator** must ensure that its **embedded generating** plant does not contribute to the permitted levels of voltage unbalance, voltage fluctuation and harmonic content specified by the **distributor** being exceeded. | Clause 3.14 is duplicated by the voltage quality requirements as set out in SIR 6.2.3 (TIR), 6.2.5 (TIR) and 6.2.6 (TIR), TS 132 and TS133 (4.12), and AS/NZS 4777.2:2020 (2.7, 2.8 and 2.11). Compliance with AS/NZS 4777.2:2020 is a TIR). | Clause 3.14 will be removed. |
| 21 | 3.15 Fault Levels<br><br>3.15.1 An **embedded generating unit** must be designed to work within and not contribute (other than an agreed contribution) to the system maximum fault level and the **feeder** capacity to which it is connected. | The intent of clause 3.15, (and clause 3.10.1(c), is duplicated by SA Power Networks' fault level requirements set out in TS132 and TS133 (4.3.1 and 4.16.2.1)<br><br>SA Power Networks does not make the same requirements for some embedded generators covered by TS129 that apply under this clause. This is an intentional choice, and reflects the fact that inverter-connected embedded generators do not contribute as much fault current as synchronous generators. | Clause 3.15 will be removed. |

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| 24 | 3.16 Earthing<br><br>3.16.1 A **large embedded generator** must ensure that its **embedded generating units** are earthed in accordance with the **distributor's** earthing requirements. The **embedded generator** must provide earth fault protection to isolate each **embedded generating unit** from the **distribution network** under earth fault conditions. | Clause 3.16 is inconsistent with SA Power Networks' earthing requirements as set out in TS132 and TS133 (4.8, 4.9.2.2). | Clause 3.16 will be removed. |
| 25 | 3.17 Interference<br><br>3.17.1 If the **distributor** notifies the **embedded generator** that its **embedded generating unit** is causing interference above the limits set out in **AS**/NZS 2344, **AS** 2279, **AS**/NZS 61000 3.2, 3.3 or 3.5, the **embedded generator** must reduce the level of interference to below these limits within 90 days. | Clause 3.17.1 is partially duplicated by other regulatory instruments, including SIR 5.2.4 (TIR).<br><br>Managing interference caused by generators outside the limits set in relevant standards is a material matter.<br><br>This requirement may refer to 'limits set out in SA Power Networks' technical standards and in the Australian Standards they refer to', instead of any specific standards.<br><br>Further, the 90-day requirement may be replaced with the requirement for embedded generators to resolve interference within timeframes set by SA Power Networks on a case-by-case basis.<br><br>References to Code clauses 3.2, 3.3 and 3.5 are now redundant, because the proposal is to remove those clauses through this final decision. | Clause 3.17 will be removed, the Commission will recommend to the Technical Regulator that it considers whether these matters should be addressed elsewhere in the State regulatory framework. |

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