Electricity

Electricity Distribution Code review

Draft Decision

January 2023

Request for submissions

The Essential Services Commission (**Commission**) invites written submissions on this paper by **Friday, 10 March 2023.**

It is the Commission's policy to make all submissions publicly available via its website (www.escosa.sa.gov.au), except where a submission either wholly or partly contains confidential or commercially sensitive information provided on a confidential basis and appropriate prior notice has been given.

The Commission may also exercise its discretion not to publish any submission based on length or content (for example containing material that is defamatory, offensive or in breach of any law).

Responses to this paper should be directed to: **Electricity Distribution Code review: draft decision**

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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
ACS	Alternative Control Services
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
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
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

WALDO	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 draft decision on changes that will apply from 1 July 2025. The Commission is seeking stakeholder responses to this draft decision by Friday 10 March 2023.

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

In practice, the Code applies only to the distribution network operated by SA Power Networks. The review 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 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 regulation.

Four main areas of change are proposed in this draft decision, relating to:

- the application of the Code
- minimum network reliability 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.

Two documents are published alongside this draft decision: a draft 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 Code notionally applies to entities licensed to operate a distribution network under Part 3 of the *Electricity Act 1996* (**Electricity Act**). In practice, the Code only applies to one such entity, SA Power Networks, which has the only distribution licence which specifies compliance with the Code. To reflect this, the draft 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 10,000 or more domestic customers, 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 under separate review.[1]

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

The draft decision is to amend the Code so it no longer applies to embedded generators. This reflects the draft proposal (explained further below) to remove all Code provisions that currently apply to

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

embedded generators in order to avoid duplication or inconsistency with national and State regulatory frameworks.

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 draft decision is to retain the performance targets and reporting thresholds in the current 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 draft 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 are concerned about recent CBD reliability, which in several recent years has not met some performance targets (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 they are near the end of their expected lifespan, which will materially affect CBD reliability in coming years.

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

Regional reliability

The draft 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.

The draft decision is that 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.

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 systemic 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 draft 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 draft 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.

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.

Planning for high impact low probability events

The Code's current minimum network reliability standards do not prescribe how SA Power Networks should plan its network to be resilient to high-impact low-probability (HILP) events. 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 HILP events. In assessing any expenditure proposal related to HILPs, the AER is required to consider this jurisdictional regulatory obligation.

SA Power Networks currently delivers network resilience to HILP events through application of its network planning criteria. In its submission to the Issues Paper, 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 Commission does not support SA Power Networks' proposal. It is important that any approach to planning for HILP events is not prescriptive. Decisions about whether resilience-related expenditure is valued by consumers necessarily require judgement, best informed by analysis of several types of evidence. This is provided for by the existing best endeavours regulatory obligation.

The AER has published guidance for network service providers on the evidence needed to support proposals for network resilience-related expenditure. Its approach involves establishing the value to consumers of expenditure for network resilience to possible HILP events, while acknowledging the limitations of using conventional techniques to do so, and so a role for other supporting evidence. The Commission supports the AER's approach.

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 draft decision is to retain the minimum customer service standards in the current Code for the 2025 – 2030 period. These continue to be important to customers and provide a baseline for SA Power Networks' customer service outcomes.

Internally, SA Power Networks uses a broader range of measures to monitor and improve customer service, including measures of customer satisfaction and the quality of telephone interactions (first call resolution).

The Commission will consider revising existing minimum customer service standards where there is evidence they are a barrier to improving customer service as measured by the metrics SA Power Networks uses within its business. The Commission does not currently have evidence that this is the case.

New or innovative customer service measures, such as measures of customer satisfaction and first call resolution, may be suitable for inclusion as parameters in the AER's Customer Service Incentive Scheme (CSIS).

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 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 draft 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 under the *Electricity (General) Regulations 2012* (Electricity Regulations). The draft 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 draft 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 the broader State framework (noting that the current Electricity Regulations expire in September 2023).

Other areas of risks to consumers

The review has considered the role of the Commission in managing risks to consumers 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 draft 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.

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 draft 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.

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 draft 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 current 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 draft 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**); a product of negotiation between SA Power Networks and public lighting customers. The broader regulatory framework, of which the AER has some oversight, provides a structure for SA Power Networks to deliver and be held accountable for timely street light repairs.

The current Code also provides for 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 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 draft decision is to remove the street light repair GSL payment from the Code. The Commission has reviewed the cost of the payment, the benefits attributed to it over time, and whether those are being delivered.

The payment has limited benefit. At best, it provides a weak incentive for people to report street light outages. The incentive is considered weak because 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 a weak incentive, the risk 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.

Next steps

The Commission welcomes responses to this draft decision by Friday 10 March 2023. The inside cover of this report explains how to make a submission, and contains contact details of Commission staff.

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

Table 1: Key dates for remainder of review

Date	Milestone
January 2023	Publication of draft decision and amendments to Code
10 March 2023	Submissions to draft decision close
June 2023	Publication of final decision and amendments to Code
January 2025	Publication of draft amendments to Electricity Industry Guideline No. 1 for consultation
June 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

Issue number	Topic and reference to full discussion	Current arrangement	Draft decision on arrangement for 2025 - 2030	Draft decision on amendments to Code
1	Application of the Code (section 3)	The Code applies to: the distributor, defined as a holder of a licence to operate a distribution network under Part 3 of the Electricity Act, and embedded generators not required to be registered under the National Electricity Rules (**NER**). 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 Distribution Network Service Providers (**DNSPs**) regulated by the AER in South Australia with 10,000 or more domestic customers. This narrows application of the Code to one distributor, SA Power Networks, which is already the case in practice. 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 References to 'SA Power Networks' replaced with references to 'the distributor' Definition' of 'SA Power Networks' removed 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. 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. 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. The Commission's current definition of low-reliability feeder will also be retained, but moved to Electricity Industry Guideline No. 1.	No amendments Minor edits for clarity in clauses 2.2.1 and 2.2.2 Definition of low-reliability feeder moved to Electricity Industry Guideline No. 1

Issue number	Topic and reference to full discussion	Current arrangement	Draft decision on arrangement for 2025 - 2030	Draft 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. 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 systemic decline.	No amendments
4	Stand-alone power systems (section 4.2)	-	The Code will not set minimum network reliability standards for Stand-alone Power System (**SAPS**) feeders. These are provided in the national regulatory framework. 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. 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 Definitions of 'SAPS feeder' and 'Regulated SAPS' added Clause 2.3.1(c)(i)(A) amended
5	Planning for high-impact low-probability (**HILP**) events (section 4.4)	SA Power Networks must apply its best endeavours in managing reliability outcomes. No Code prescriptions for network planning.	No change to current arrangements. The Commission supports the AER approach to assessing expenditure to provide resilience to HILP events.	No amendments

Issue number	Topic and reference to full discussion	Current arrangement	Draft decision on arrangement for 2025 - 2030	Draft 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.	Minimum customer service standards will not be changed in the next version of the Code. The Commission will revise existing minimum customer service standards only where there is evidence they are a barrier to improving customer service as measured by the metrics SA Power Networks uses within its business. New customer service measures may be suitable for inclusion as parameters in the Australian Energy Regulator's (**AER**) Customer Service Incentive Scheme (**CSIS**).	No amendments
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 National Electricity Rules (**NER**). 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. 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 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	Draft decision on arrangement for 2025 - 2030	Draft decision on amendments to Code
8	Risks posed by Virtual Power Plants (VPPs) (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. These risks include potential impacts on security, reliability, and quality of supply, and risks to customers when VPPs control equipment on their behalf. The requirement for provisions to address these risks will be considered by reviews being conducted by the Department for Energy and Mining (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. 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	Draft decision on arrangement for 2025 - 2030	Draft decision on amendments to Code
11	Street light repair Guaranteed Service Level (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 a weak incentive for people to report street light outages. The risk that there will be fewer reports after it is removed is low and manageable. Annual reporting on street light outages and repairs will be retained during the 2020 – 2025 period.	Clause 2.3.1(b)(ii) removed

2 Introduction

This draft decision explains the proposed 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.[2]

The Electricity Distribution 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.[3] 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] Australian Energy Market Commission, 2021, Access, pricing and incentive arrangements for DER. This change introduces some consumer protections for export services to the national framework.

[3] Essential Services Commission of South Australia, SA Power Networks 2020 reliability standards review

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 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 may be 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 frameworks.

2.2 Review process

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

- SA Power Networks' operational performance reporting to the Commission[4]
- submissions to the Issues Paper published in April 2022[5]
- 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,[6] and
- expert technical review of the existing provisions for connection of embedded generation.

2.3 Outline of draft decision

Four main areas of change are proposed in this draft decision. These relate to: application of the Code, minimum network reliability standards, distributed energy resources, and obligations for the timely repair of street lights.

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

The Commission welcomes responses to this draft decision by Friday 10 March 2023 and plans to publish a final decision on any changes to the Code in June 2023.

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

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

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

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 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 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 draft 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 10,000 or more domestic customers. This clarifies that the Code operates alongside the national framework, as it already does in practice.

The draft 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 10,000 or more customers, that is, to SA Power Networks.[7]

The relevant draft amendment is to the definition of distributor, which has been changed in the draft revised Code to mean a DNSP regulated by the AER in South Australia with 10,000 or more domestic customers. This narrows application of the Code to SA Power Networks, which affects the meaning of clause 1.2

The new definition 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 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.

Other distribution licences are held by small-scale operators. As most sections of the Code would not be practical or reasonable to apply to these operators, their licence conditions are tailored to the nature of each operation. Customer protections that apply in small-scale distribution networks licenced by the Commission are currently being reviewed (through the Small-scale energy networks consumer protection framework review).[8]

Amending the Code so it explicitly applies only to DNSPs regulated by the AER in South Australia with 10,000 or more domestic customers means that the Code will not apply to excluded networks (reflecting a similar definition used in the Electricity Act).[9] This will align the scope of the Code with its current purpose within the broader regulatory framework for distribution services. It will also reflect how the Code is currently applied.

The Issues Paper identified the possibility of limiting application of the Code to SA Power Networks. The SA Power Networks' submission to the Issues Paper put the view that:

> *'the Code should apply to any licensed distributor who supplies electricity from the NEM to their customers over public land. This would ensure that the customer protections provided to SA Power*

[7] DNSPs regulated by the AER in South Australia are listed here

[8] See: Small-scale energy networks consumer protection framework review

[9] 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.

> *Networks' customers (for example reconnecting electricity supply after disconnection) would also protect the customers of that other licensed distributor.'* [10]

The Commission's view is that customers of small-scale networks should have 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.

3.2 Code will not apply to embedded generators

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

[10] SA Power Networks 2022, Submission to Electricity Distribution Code review Issues Paper, p. 10

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[11] 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 each of the 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.[12] 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.

[11] 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.

[12] 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 draft 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 draft 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 draft 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 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

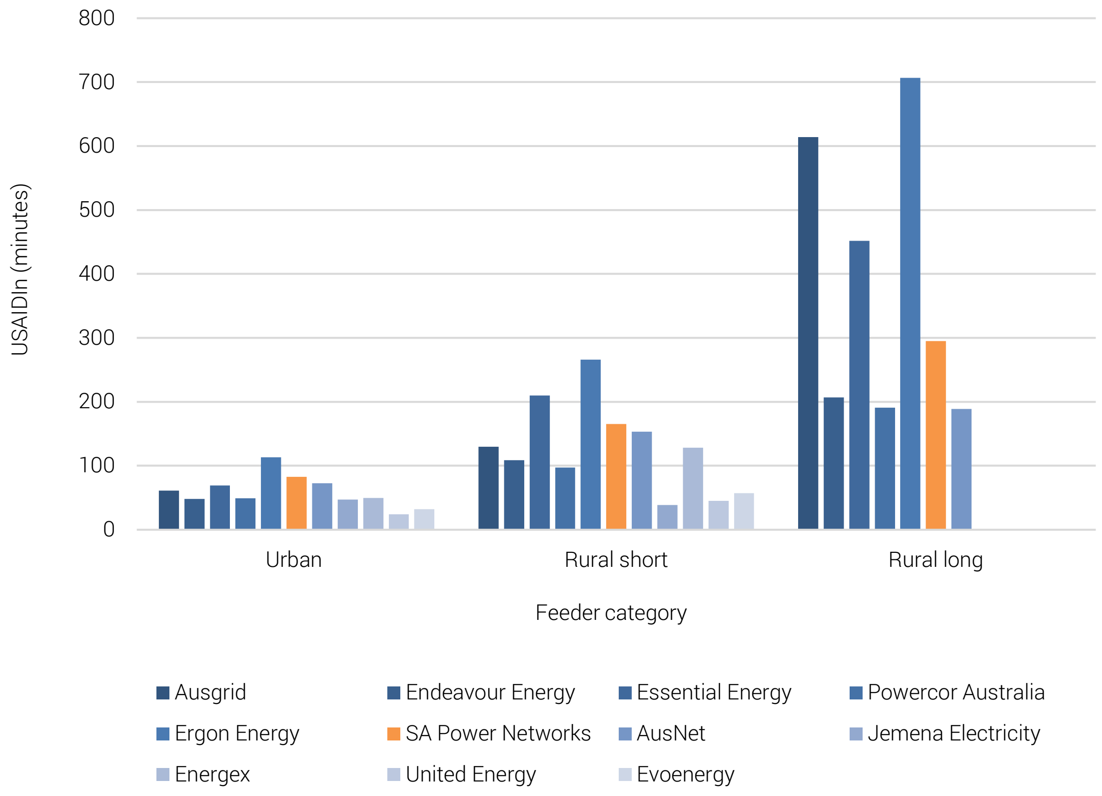
4.1.2 Legislative responsibilities

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 National Electricity Market (**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 4.1.4.

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.

4.1.3 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.[13]

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.[14]

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).

[13] This matter was explored extensively at the last Code review (see: SA Power Networks reliability standards review – final decision, pp. 10-16)

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

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SA Power Networks is in the early stages of developing its regulatory proposal for the 2025 – 2030 period. To inform its community engagement on its regulatory proposal, SA Power Networks has prepared scenarios of different reliability outcomes, and estimated the associated repex and augex. All scenarios have been published on its Talking Power website.

The early repex and augex estimates provide 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, and that meeting minimum network reliability standards is an important driver of that change. The repex and augex estimates are not actual costings, and as such have a wide confidence interval. Final expenditure provided for in the distribution determination is subject to the AER's review of what is prudent and efficient.

The early estimates are as follows:

- Repair and replacement expenditure

  SA Power Networks is developing a proposal for new repex to manage equipment failures so as to maintain reliability and safety and manage bushfire risk. The proposal is based on SA Power Networks' modelling of increased equipment failures during 2025 – 2030, as its assets deteriorate.

  The step change indicated by SA Power Networks is from $670 million across the 2020 – 2025 period to $1,210 million across the 2025 – 2030 period. That step change would increase the repex component of a typical residential electricity bill from $18 to $39 per annum.[15]

- Augmentation expenditure

  SA Power Networks is developing a proposal for new augex to maintain reliability by managing the impact of outages when they occur, and managing the frequency of some types of outages (for example, those arising from lightning strikes and animal interference). The components of this expenditure are installation of automatic switching and remote monitoring on CBD feeders and on rural long feeders.

  The step change indicated by SA Power Networks is from $84 million across the 2020 – 2025 period to $105 million across the 2025 – 2030 period. That step change would increase the augex component of a typical residential electricity bill from approximately $4.30 to $5.40 per annum.[16]

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).

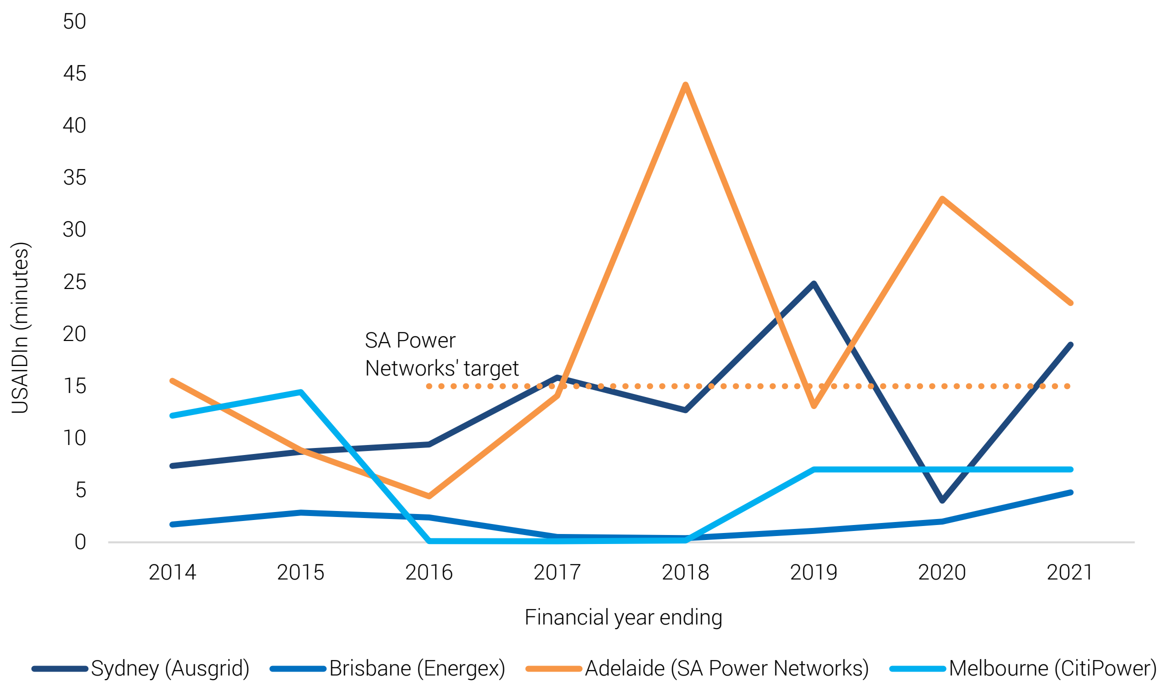
[15] See SA Power Networks 2022, Focused conversation – managing a reliable, safe and resilient network – workshop two presentation and notes, slides 55-58, 62, 76, detail about Scenario 2

[16] SA Power Networks 2022, Focused conversation –managing a reliable, safe and resilient network – workshop three presentation and notes, slides 76-77, detail about Scenario 2

4.1.4 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.

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.[17]

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,[18] and stakeholder views that the CBD is important as a

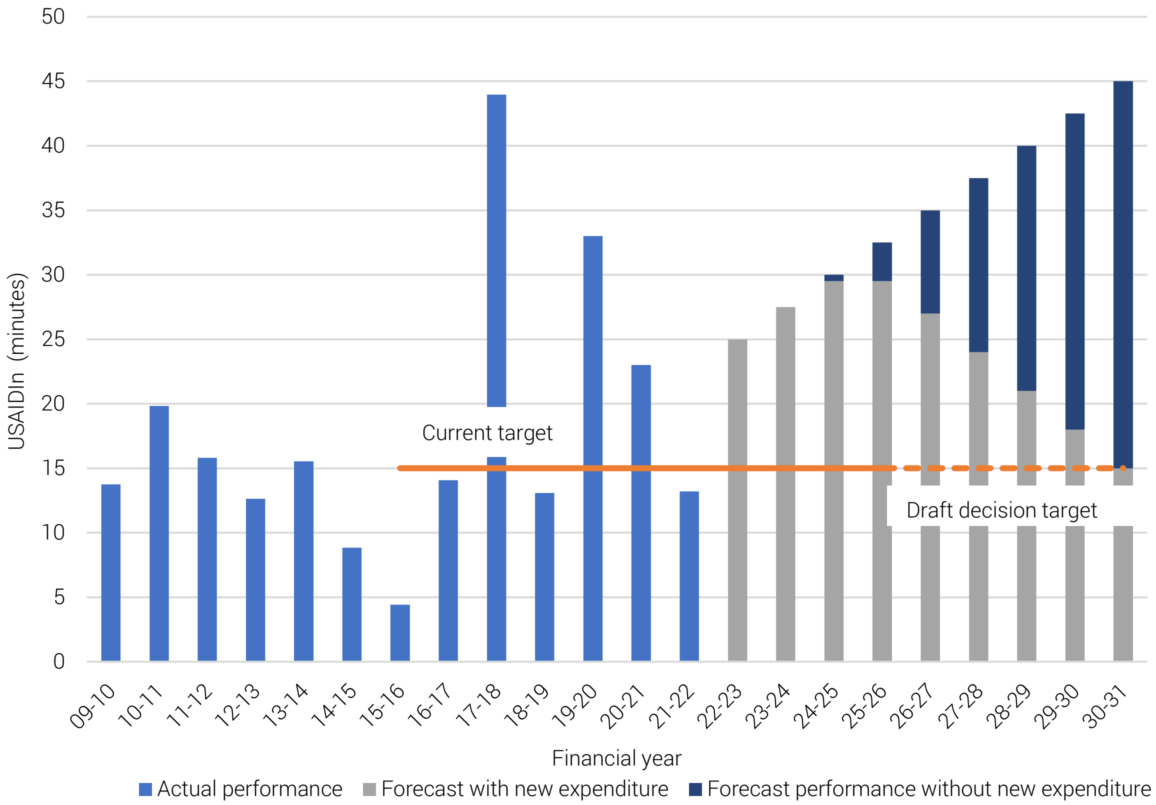
[17] Information about SA Power Networks' historical performance outcomes for each regulatory year is available at: ESCOSA - SA Power Networks' regulatory performance, and in SA Power Networks' 2021 fact sheet Maintaining reliable and cost-effective electricity supply for Adelaide's CBD

[18] 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, 2020, Final decision – SA Power Networks 2020-25,

centre for government, services and commerce. In its early engagement on its regulatory proposal, SA Power Networks has presented evidence that the condition of some underground cables in the CBD will materially affect CBD reliability in coming years. Based on asset condition and without additional expenditure, SA Power Networks has forecast that CBD reliability may decline, with 45 minutes of USAIDIn predicted by 2030-31.

Predicted declines are illustrated in Figure 3 below. These forecasts are based on the predictions of SA Power Networks' Forecast Risk Cost Model. SA Power Networks will refine its forecasts in coming months, as it receives updated modelling on asset condition.

Figure 3: Actual and forecast USAIDIn performance on SA Power Networks' CBD feeders, 2009-10 to 2030-31



Data sources: SA Power Networks' reporting to the Commission; SA Power Networks, September 2022, Focused conversation – CBD reliability—workshop two presentation, slide 60

SA Power Networks is developing a CBD asset replacement program for inclusion in its 2025 – 2030 regulatory proposal. It has provided an indication of expenditure needed to return CBD reliability to the targets in the current Code by the end of the 2025 – 2030 period. These are indicative cost estimates that SA Power Networks expects to refine before it submits its regulatory proposal to the AER.

SA Power Networks expects expenditure on CBD reliability to increase from $34 million across the 2020 – 2025 period to $111 million across the 2025 – 2030 period. This would change the CBD component of a typical residential electricity bill from $1.55 to $4.15 per annum.[19]

Attachment 10: Service target performance incentive scheme, pp. 10-11 and Australian Energy Regulator, 2019, Value of customer reliability review: final decision.

[19] SA Power Networks 2022, People's Panel Recommendation – CBD Reliability, pp. 7-8, detail about Scenario 2

The CBD reliability program[20] is forecast to include:

- $51 million to replace 20 kilometres of 11kV lead cable (16 percent of all 11kV lead cable), reducing the likelihood of outages due to cable failure
- $28 million to automate 20 CBD feeders and install remote customer monitoring (resulting in 40 percent (26) of all CBD feeders being automated), reducing the impact of outages when they occur
- $5 million to replace two kilometres of 33 kV lead cable (eight percent of all 33kV lead cable), reducing the likelihood of outages due to cable failure
- $24 million to replace distribution and substation equipment including replacement of 10 distribution switches with restricted access (a 20 percent reduction in the number of switches with restricted access), and increase inspections and maintenance, reducing the likelihood of outages and the impact when they occur.

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 clearly set out 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.[21] 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 generally the terms of the Commission's Enforcement Policy).[22]

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[20] SA Power Networks 2022, CBD reliability – focused conversation – scenario summary

[21] 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.

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

4.2 Regional reliability

The draft 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 systemic 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

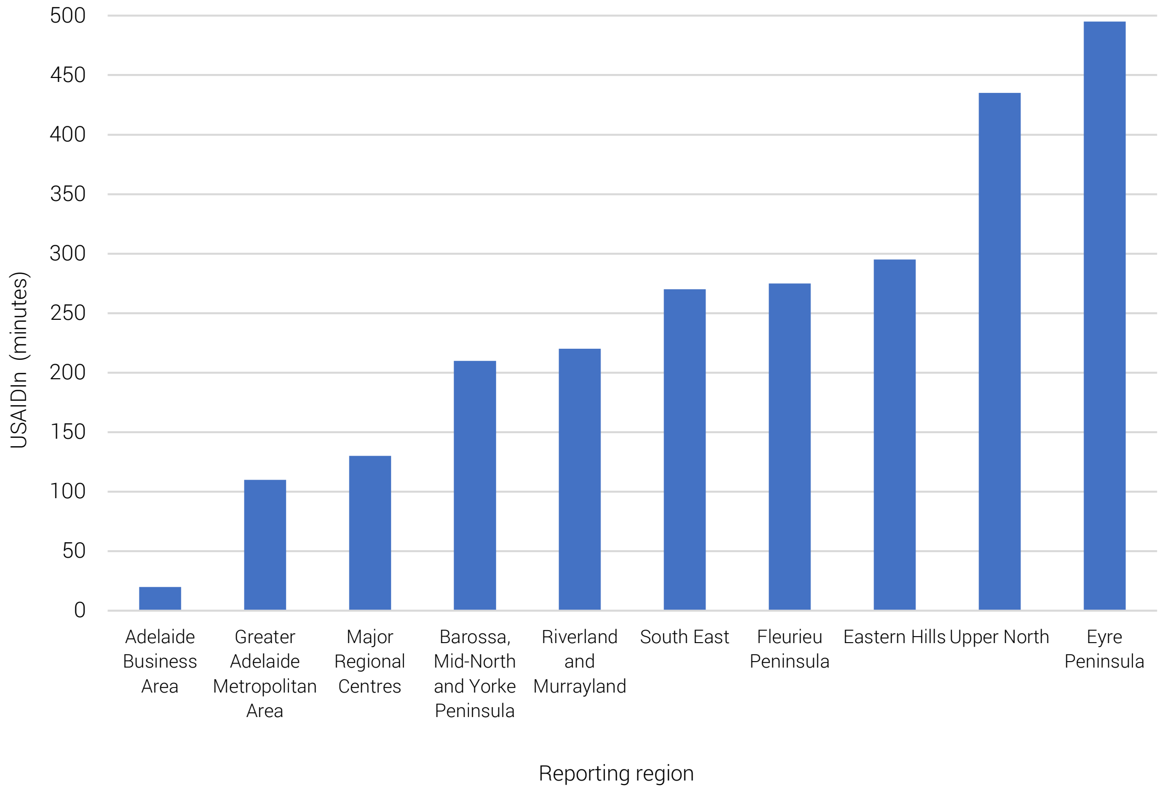
SA Power Networks is required to report on regional reliability. This promotes transparency and accountability, allows the Commission to monitor performance trends, and identify any areas that may require targeted improvements.

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.[23]

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

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

Figure 4: 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,[24] 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 draft 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'.*[25] 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.[26]

[24] Essential Services Commission of South Australia, Electricity Industry Guideline No. 1, Electricity Regulatory Information – Requirements – Distribution, Version G1/13.1
[25] SA Power Networks, 2021-22 Annual Reliability Performance Report to the Commission, p. 9
[26] 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 lighting strikes) and animal interference (particularly possums). SA Power Networks has managed this by installing lighting 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.

By way of further example, in the Riverland and Murrayland, 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.

SA Power Networks has indicated that an additional $100 million in repex and $15 million in augex would be required across the next period to maintain regional reliability.[27]

SA Power Networks has indicated that repex planned to efficiently meet minimum network reliability standards for feeder categories (as set out in section 4.1.3) 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.[28]

Augex planned to efficiently meet minimum network reliability standards for feeder categories (as set out in section 4.1.3) 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.[29]

SA Power Networks is also developing a proposal for an additional $15 million of expenditure across 2025 – 2030 for remediation works on low-reliability feeders.[30]

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 will emerge through the remainder of the SA Power Networks' engagement program, and will include:

- 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, research being designed by SA Power Networks with input from the Community Advisory Board reset subcommittee, available in January 2023, and

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[27] SA Power Networks 2022, Focused conversation – managing a reliable, resilient and safe network – workshop 2, slides 58 – 62, detail about Scenario 2, and SA Power Networks 2022, Focused conversation – managing a reliable, resilient and safe network – workshop 3, slide 70, detail about regional reliability improvement within Scenario 3

[28] 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

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

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

- findings of the People's Panel that will deliberate during February and March 2023 and weigh the expenditure recommendations from each 'focused conversations' stream.

The AER may include in its distribution determination expenditure other than that 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 draft decision is to continue to require regional reporting, and monitoring of reliability outcomes for regions, across the 2025 – 2030 period.[31] 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 systemic 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.[32]

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 systemic 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.[33]

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

[31] 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

[32] 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

[33] 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 draft 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 (**SAPS**) 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.[34] 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.[35] 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.[36]

The national framework requires that SAPS customers are given the same consumer protections as those on the interconnected network.[37] 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.[38] 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.[39]

SA Power Networks must develop those performance targets with regard to the SAPS quality of supply principle.[40] That principle requires that the reliability of supply for SAPS customers should be no worse than if they were served by the interconnected network.[41]

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[34] Australian Energy Regulator, August 2022, Updating instruments for regulated stand-alone power systems, Final decision

[35] 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

[36] 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.

[37] Australian Energy Regulator, August 2022, Updating instruments for regulated stand-alone power systems, Final decision

[38] National Electricity Rules Clause 5.13B.1

[39] National Electricity Rules Schedule 5.13

[40] National Electricity Rules Clause 5.13B.1(d)(1)

[41] SAPS 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 draft 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.[42] 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.'* [43]

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 draft 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,[44] 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.

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 draft 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.

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.[45]

42 Australian Energy Regulator, August 2022, Distribution Reliability Measures Guideline
43 Australian Energy Regulator, August 2022, Distribution Reliability Measures Guideline, p. 6
44 SA Power Networks submission, pp. 24-25
45 Clause 2.3.1 (a)

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.[46]

The Commission's draft 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.[47]

The Commission's draft 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 marked-up version of the Code that accompanies this draft decision, Clause 2.3.1(c)(i)(A) and the definition of 'interruption' will be amended to reflect this. These amendments are consistent with the changes to exclusions set out in the DRMG at section 3.3.

Further, definitions of 'Regulated SAPS' and 'SAPS feeder' will be added to the Code, which will be the same as those in the DRMG. The definition of 'feeder' will be updated so it is the same as in the DRMG.

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 that there are no practical issues that must be addressed to do so.[48]

4.4 Planning requirements for high-impact low-probability events

The Commission supports the AER approach to assessing expenditure to provide resilience to high-impact low-probability (**HILP**) events. No requirements for network planning will be introduced to the Code.

One consideration in managing a distribution network is its 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 to be resilient to HILPs. The Code sets output standards for normalised performance. Where HILPs occur and performance targets are not met, the standard may still be achieved if SA Power Networks has applied its best endeavours in attempting to do so. Where HILPs result in Major Event Days (**MEDs**) their impact is excluded from assessing normalised performance. The Code requires that SA Power Networks apply its best endeavours to managing reliability outcomes on MEDs.

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

[47] Clause 2.3.1 (c)

[48] SA Power Networks submission, pp. 24-25

SA Power Networks has responsibility for assessing the risk and uncertainty around HILPs, planning the extent to which the network is resilience to HILPs, 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 currently delivers resilience to HILP events by applying a set of internal network planning criteria.

The primary purpose of SA Power Networks' internal network planning criteria is 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.[49] SA Power Networks applies the 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 HILP events.

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.[50] It is concerned that the AER favours an alternative 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 to HILP events.[51] It is concerned this would not meet customer expectations.

In its submission to the Issues Paper, SA Power Networks requested that a simplified version of its current network planning criteria be incorporated in the Code.[52] It argued this would provide certainty around planning for resilience to HILP events, because it would establish a regulatory obligation for some resilience-related expenditure.

The Commission does not support incorporating a simplified version of SA Power Networks' internal planning criteria into the Code. Such an obligation would risk that the associated costs may not be acceptable to consumers in all instances.

The AER's approach to resilience-related expenditure is concerned with establishing the value to customers of addressing possible HILP event/s, but is not strictly probabilistic.[53] The AER has published guidance for network service providers on the treatment of resilience-related expenditure under the NER.[54] The note addresses how network service providers might consider and demonstrate that such expenditure is prudent and efficient.

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[49] SA Power Networks, Distribution Annual Planning Report 2021/22 to 2025/26, pp. 40-47

[50] SA Power Networks submission, p. 7, 26 - 28

[51] SA Power Networks submission, p. 7, 26 - 28

[52] SA Power Networks submission, p. 7, 26 - 28

[53] The AER does however require 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

[54] Australian Energy Regulator 2022, Network resilience – note on key issues

The AER's approach involves examination of whether the benefits of resilience-related expenditure outweigh the costs,[55] but also acknowledges the limitations of using conventional techniques to establish the benefits of such expenditure.[56] Because of those limitations, the AER recognises a role for the use of other supporting evidence, such as willingness-to-pay studies.[57]

Importantly, the AER recognises that network service providers should consider consumer and community preferences for network resilience,[58] because of the inherent uncertainty surrounding HILP events and future network needs, demand, and energy mix.

In assessing any expenditure proposal related to HILPs, the AER is required to consider jurisdictional regulatory obligations. For SA Power Networks, this means the AER must consider the existing regulatory obligation, that SA Power Networks apply its best endeavours in pursing reliability performance outcomes, in both normal and extreme conditions.

The existing regulatory obligation is not prescriptive. The Commission considers this appropriate in relation to planning for HILP events, because decisions about whether resilience-related expenditure is valued by consumers necessarily require judgement. Those decisions may be usefully informed by:

- 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 AER's guidance on network resilience expenditure allows for these matters to be considered, and is consistent with the Code's best endeavours regulatory obligation. The Commission supports the AER's approach to resilience-related expenditure.

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55 Australian Energy Regulator 2022, Network resilience – note on key issues, p. 12

56 See Australian Energy Regulator 2022, Network resilience – note on key issues p. 10. Benefits to customers of avoided outages are quantified by combining information about the likelihood of an outage, its expected impact (measured as volume of unserved energy), and the value of that impact (measured using the suite of Values of Customer Reliability (VCRs) produced by the AER). Customers tend to understate how important reliability is in relation to HILP events until one occurs. Despite recent AER work on VCRs for WALDOs, the value of reliability in HILP events continues to be under represented in the current suite of VCRs. This means that expenditure to maintain the resilience of the network may not show a net benefit even if valued by consumers and the community.

57 Australian Energy Regulator 2022, Network resilience – note on key issues, pp. 11-12

58 Australian Energy Regulator 2022, Network resilience – note on key issues, p. 9-10

4.5 Minimum customer service standards

The draft decision is to retain the minimum customer service standards in the current Code for the 2025 – 2030 period. These continue to be important to customers and provide a baseline for SA Power Networks' customer service outcomes.

The Commission will revise existing minimum customer service standards only where there is evidence they are a barrier to improving customer service as measured by the metrics SA Power Networks uses within its business.

New customer service measures may be suitable for inclusion as parameters in the AER's Customer Service Incentive Scheme (**CSIS**).

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

- SA Power Networks must use its best endeavours to respond to 85 percent of telephone calls within 30 seconds.[59]
- SA Power Networks must use its best endeavours to respond to 95 percent of written enquiries within five business days.[60]

Since 2020-21, SA Power Networks has also been obliged to monitor and report on customer satisfaction with communication quality.[61] 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.[62] SA Power Networks' fault 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 and revise those when clearly outdated (such as in revising the definition of 'written enquiry' ahead of the 2020 – 2025 period).

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.

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[59] Clauses 2.1.1, 2.1.2, 2.1.3 and 2.1.5

[60] Clauses 2.1.1, 2.1.4 and 2.1.5

[61] See Electricity Industry Guideline No. 1, OP 1.3

[62] 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.

4.5.2 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.[63]

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 Customer Service Incentive Scheme (**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.[64]

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)[65]
- 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.[66]

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

4.5.4 Engagement on revised customer service measures

SA Power Networks is currently engaging with customers on its use of customer service measures, including which best define minimum levels of service (for consideration in this Code review) and which might be used in the CSIS to incentivise improvements. [67]

SA Power Networks considers that the Code's minimum customer service measures have become less relevant to customers over time. [68] In particular, SA Power Networks considers that the telephone responsiveness measure is no longer appropriate, and that measures of customer satisfaction

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[63] SA Power Networks 2022, Focused conversation – customer experience and interactions – workshop 2 presentation, slide 17
[64] See Australian Energy Regulator 2019, Customer Service Incentive Scheme explanatory statement and scheme design
[65] See Australian Energy Regulator 2021, Final Decision, AusNet Services Distribution Determination 2021 to 2026, Attachment 12, Customer service incentive scheme
[66] See AER 2021, Final Decision, CitiPower, PowerCor and United Energy Distribution Determination 2021 to 2026, Attachment 12, Customer service incentive scheme
[67] SA Power Networks 2022, Customer Experience and Interactions focused conversations engagement stream
[68] SA Power Networks submission, pp. 7–8, 34 - 35

(measured since 2018) and first contact resolution (measured since the start of 2022) are more relevant.[69]

More evidence of customer views on service measures will emerge through the remainder of the SA Power Networks' engagement program, which the Commission may consider in making its final decision.

4.5.5 Commission's position on the minimum customer service standards

The minimum customer service standards (for telephone and written responsiveness) in the current Code provide a baseline for SA Power Networks' customer service outcomes.

The Commission will revise existing minimum customer service standards only where there is evidence they are a barrier to improving customer service as measured by the metrics SA Power Networks uses within its business.

New and innovative customer service measures, such as measures of satisfaction and first call resolution, 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 CSIS.

[69] SA Power Networks submission, pp. 7–8

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.[70]

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.[71]

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, by reviewing national and State frameworks, whether there is a gap in the regulation of DER that needs to be addressed through the Commission's regulatory framework.[72]

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 frameworks.

70 The licensing framework through which the Commission can impose technical conditions on some generators is under review (see Department for Energy and Mining, 2022, Review of the South Australian Electricity Licensing Framework). 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, 2021, Electricity generation licence exemption).

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

72 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. [73] These include expanding capacity for export services (by requiring distributors to plan for efficient provision and through possible development of financial incentive arrangements[74]), 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.[75] 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.

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

[74] 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, 2022, Incentivising and measuring export service performance, p. 5),

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

5.1 Review of existing provisions for connection of embedded generators

The draft 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. They were last reviewed in 2010.

The connection process and associated financial charges for embedded generators are now covered in the national framework, and the proposal is to remove that content (clauses 3.2 – 3.8). In its submission to the Issues Paper, SA Power Networks indicated its support for removing those clauses.[76]

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.

[76] SA Power Networks submission, 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. [77]

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 draft decision.

The proposal is to remove 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.

Three clauses are not addressed by other regulatory provisions. These are clauses 3.10.1(b), 3.13 and 3.17. The proposal is to remove those clauses from the Code and 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.[78] 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.[79]

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.

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 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,

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[77] 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).

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

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

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 submits that *'it would be useful for the Code to expressly acknowledge that SA Power Networks may employ appropriate strategies to manage this scenario'.*[80] 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.

5.2.1 Risks posed by the operation of VPPs

The draft 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.[81]

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[82]), 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 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.*' [83]

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*

80 SA Power Networks submission, p. 20
81 Australian Energy Market Operator, 2021, AEMO NEM Virtual Power Plant Demonstrations Knowledge Sharing Report 4, p. 20
82 Typically each customer in a VPP has DER with a small capacity, and connection is made using SA Power Networks' Model Standing Offer or the Deemed Standard Connection Contract (NERL Schedule 2).
83 SA Power Networks submission, p. 14

Networks to ensure that the simultaneous operation of the many individual generation plants does not adversely impact the distribution system and other customers.' [84]

SA Power Networks also expressed this position in its submission to the DEM Review of the South Australian Electricity Licensing Framework.[85] 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.[86]

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.'* [87]

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.[88] 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.

VPPs are exempt from the need to hold a generation licence while the review is underway.[89] This follows an initial exemption which was in place during the AEMO VPP demonstration period.[90] The exemption is required because the combined capacity of VPPs exceeds the Electricity Act's statutory licensing exemption threshold of 100kVA, 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.

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84 SA Power Networks submission, p. 15
85 SA Power Networks submission to DEM review, p. 3
86 SA Power Networks submission to DEM review, pp. 3-4
87 SA Power Networks submission to the Review of the South Australian Electricity Licensing Framework, p. 4
88 Department for Energy and Mining, 2022, Review of the South Australian Electricity Licensing Framework
89 Essential Services Commission of South Australia, 2021, Electricity generation licence exemption – Virtual Power Plant operations, electric vehicle charging operators, and sub-5MW operators
90 Essential Services Commission of South Australia, 2019, Enrolled participants in AEMO's Virtual Power Plant demonstration program

Second, the AER is conducting a Review of Consumer Protections for New Energy Services.[91] 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 draft 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 draft 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.
- 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.[92] 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.

[91] Australian Energy Regulator, 2022, Review of Consumer Protections for New Energy Services
[92] SA Power Networks, Model Standing Offer 3602

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. [93] SA Power Networks has separate deemed contracts for small retail customers and large retail customers.[94] 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).[95]

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.[96] 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 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.*[97]

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 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

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93 Deemed Standard Connection Contract, Schedule 2 of the NERR, clause 6.6(a), also see NERR 147A(1).
94 SA Power Networks, [Deemed Standard Connection Contract 3603] and [Deemed Standard Connection Contract 3604]
95 In clauses 6.3
96 SA Power Networks submission, p. 19
97 SA Power Networks submission, p. 13

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. [98]

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.

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.[99]

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[100] (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.

Staff at the Office of the Technical Regulator (**OTR**) have 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,[101] 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.[102]

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. 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 Commission' licensing framework through which the Commission can impose conditions on some generators is under review.[103] While this 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.[104] 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

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[98] 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).

[99] SA Power Networks, p. 16

[100] 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.

[101] Electricity Act s. 60, Electricity Regulations s. 55(1)(b)

[102] Electricity Act s. 70(1)

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

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

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'.* [105]

The Commission has made the draft 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.

[105] SA Power Networks submission p. 17, see also suggested clauses on p.18

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 Code has two 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,[106] 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.[107]

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

> The draft 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.

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 there has been increased oversight by the AER.[108,109]

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, 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 or the AER has a formal role monitoring or ensuring compliance with the framework.

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[106] Clause 2.3.1(b)(i)

[107] Clause 2.3.1(b)(ii)

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

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

However, the framework is an important part of the regulatory setting. The framework 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.[110]

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 (ACS) 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. This is sufficient 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.[111]

The Commission acknowledges that there will be a diversity of views on service levels within the PLWG. However, the draft decision is that the street light repair service standard is no longer required. In making this draft 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 ACS 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:
  - 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

[110] In discussions with the AER, it has indicated it relies on the framework as evidence that customers support service levels in making its decision on price caps.

[111] SA Power Networks submission, p. 7

- that operational reporting to public lighting customers is satisfactory, with regular detailed reports being made to the PLWG, which will be further formalised with reporting through SA Power Networks' public lighting portal to be established before the end of 2025,[112] and
- that public reporting of the timeliness of street light repairs occurs through SA Power Networks reporting to the AER, there is no need for the Commission to also require public reporting.[113]

6.2 Street light repair GSL payment

> The draft decision is to remove the street light repair GSL payment from the Code, on the basis that its benefit is limited to being a weak 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.

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.[114]

The draft decision is to remove the street light repair GSL payment from the Code. In making this draft 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 a weak 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 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 will provide an incentive for it to develop a solution.

The Commission will require reporting through the next period to monitor this risk. SA Power Networks will be required to report annually on the number of street light outages reported by the public, time taken to repair street lights, methods used to obtain information about street light outages, and complaints received from street light customers and public lighting consumers.

[112] SA Power Networks submission, p. 29
[113] See: AER, SA Power Networks Network information – RIN responses, Annual reporting RIN templates – 3.6.7.2 – Timely repair of faulty street lights
[114] Clause 2.3.1(b)(ii)

6.2.1 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.

6.2.2 A cost-effective alternative to distributor night patrols

Initially, this GSL payment was included in the Code because it was considered to be a cost-effective alternative to the distributor patrolling the streets at night to identify outages.[115]

Since then, the outage rate has declined, and there has become less need for information from the field to identify outages.[116] 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.

6.2.3 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[117]), current evidence suggests that the GSL payment provides only a weak 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.

[115] 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

[116] 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.

[117] Mr Arthur Marsh, Submission to Issues Paper

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; this did not impact 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.[118]

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.

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, which forms a condition of its contracts with 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).

The Commission will monitor the low risk that remains by requiring annual reporting on street light outages. The existing requirement that SA Power Networks report on the number of street light outages reported by the public and time taken to repair street lights will be retained, but be required annually not quarterly. Annual reporting requirements will also include methods used to obtain information about street light outages, and complaints received from street light customers and public lighting consumers.

This annual reporting will provide more detail than SA Power Networks' reporting on street light outages to the AER.[119] These requirements will be a transitional measure and may not be required beyond the 2025 – 2030 regulatory period.

6.2.4 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' submission to the Issues Paper that, if the GSL payment is to be retained, it should be revised to remove the recurring element, establish a

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[118] 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.

[119] For current reporting requirements, see: AER, SA Power Networks Network information – RIN responses, Annual reporting RIN templates – 3.6.7.2 – Timely repair of faulty street lights

separate timeframe for complex faults (such as cable faults), and limit payments to the person whose premises are adjacent to the street light.[120]

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.

6.2.5 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.[121]

[120] SA Power Networks, p. 33

[121] 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.

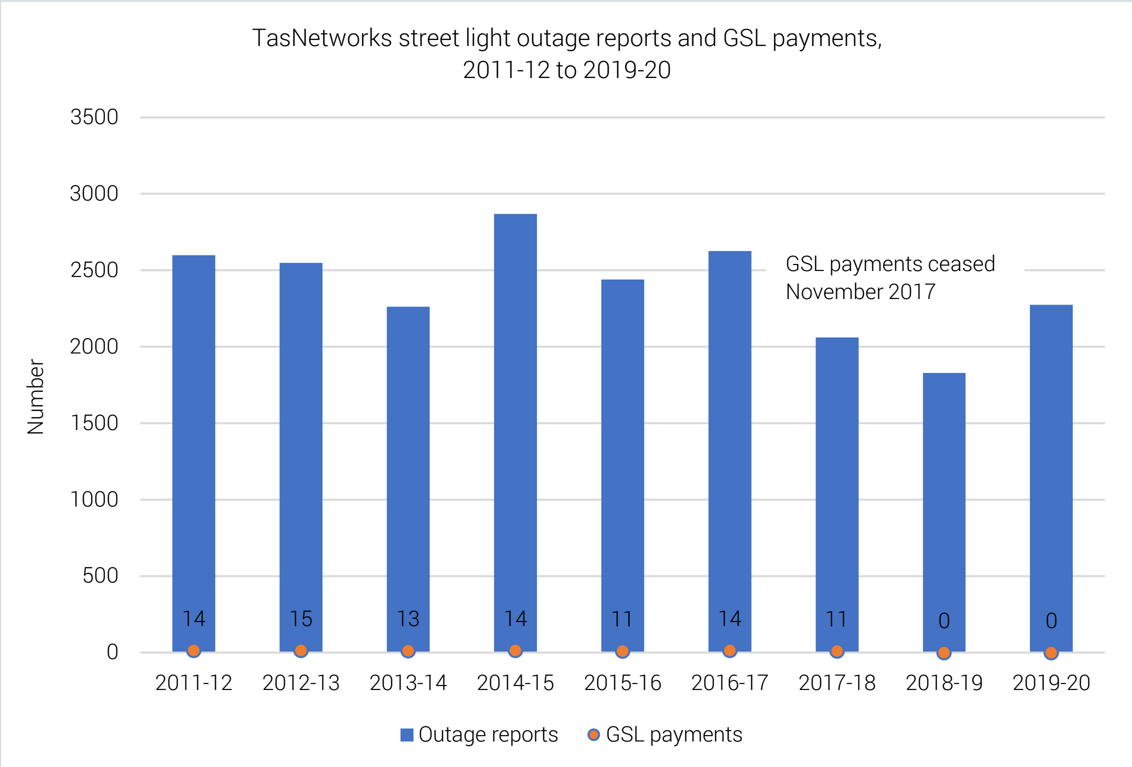
The $30 one-off payment applied if a street light outage was not repaired within seven days. It was made to the first customer to report the outage, where the outage occurred on that customer's street. Unlike the SA Power Networks payment, which is made automatically, customers had to apply to TasNetworks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

7 Next steps

The Commission welcomes responses to this draft decision by Friday 10 March 2023. The inside cover of this report explains how to make a submission.

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

The Commission plans to publish a final decision on any changes to the Code in June 2023.

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.

These, and other key dates for the remainder of the review are set out in Table 5 below.

Table 5: Key dates for remainder of the review

Date	Milestone
January 2023	Publication of draft decision and amendments to Code
10 March 2023	Submissions to draft decision close
June 2023	Publication of final decision and amendments to Code
January 2025	Publication of draft amendments to Electricity Industry Guideline No. 1 for consultation
June 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)[122]	Four years of data available following the first post-privatisation improvements to data accuracy.
2010 – 2015	four years of data (2005-06 – 2008-09)[123]	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 draft 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.

[122] 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

[123] 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.[124, 125]

The Commission considers network reliability in 2005-06 as a proxy 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

124 Section 23 of the Electricity (Miscellaneous) Amendment Act 1999
125 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	Draft decision
1	1.5 Definitions Australian Standard electricity distribution determination embedded generator embedded generating unit good electricity industry practice large embedded generator small embedded generator	As a result of the draft 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 3.9.1 Large embedded generators must comply with the following requirements: (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	Draft 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	Draft 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 3.10 .1 The capacity of **embedded generator**'s plant shall not exceed the capacity of the **distribution network** in terms of: (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	Draft 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). 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. The meaning of the phrase 'provide emergency energy' may be better expressed as 'supply energy'. 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.' 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). 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.

Item number	Clause (EDC 13.1 numbering shown)	Discussion	Draft decision
14	3.11 Scheduling 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). '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. SA Power Networks has a defined process for connections and disconnections, supported by the national regulatory framework. 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 3.12.1 Unless otherwise agreed with the **distributor**, any **embedded** generating **unit** over 1MW must: (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). 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). This is also noted in the discussion on clause 3.9.1(b).	Clause 3.12.1(b) will be removed.

Item number	Clause (EDC 13.1 numbering shown)	Discussion	Draft decision
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). 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 3.13.1 An **embedded generator's** plant shall be able to: a) respond safely to network disturbances b) shut down safely without external electricity **supply** c) restart following loss and restoration of **supply**, and 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. 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. AEMO is currently working on better defining DER impacts on operational stability[126] 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.

[126] See: AEMO DER operations workstream

Item number	Clause (EDC 13.1 numbering shown)	Discussion	Draft decision
20	3.14 Voltage Quality 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 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) 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.

Item number	Clause (EDC 13.1 numbering shown)	Discussion	Draft decision
24	3.16 Earthing 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 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). Managing interference caused by generators outside the limits set in relevant standards is a material matter. 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. 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. References to Code clauses 3.2, 3.3 and 3.5 are now redundant, because the proposal is to remove those clauses through this draft 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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