UTILITIES COMMISSION
OF THE NORTHERN TERRITORY

Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels) Review

Final Decision Paper

8 June 2023

Disclaimer

Enquiries

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Contents

Abbreviations and acronyms

AER	Australian Energy Regulator
AER Guidelines	AER's (Retail Law) Performance Reporting Procedures and Guidelines
AER Methodology	AER's Final Position – Regulatory Treatment of Inflation
ANU	Australian National University
Code	Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels)
Commission	Utilities Commission of the Northern Territory
CPI	consumer price index
Draft Decision	Electricity Industry Performance Code Review Draft Decision (February 2023)
EDL	EDL NGD (NT) Pty Ltd
Eni	Eni Australia Limited
ER Act	*Electricity Reform Act 2000*
ESS Code	former Electricity Standards of Service Code
Generator	an entity holding a generation licence granted by the Commission under the ER Act
GSL	guaranteed service levels
GSL Code	former Guaranteed Service Levels Code
IES	Indigenous Essential Services, a not-for-profit subsidiary of the Power and Water Corporation
Issues Paper	Electricity Industry Performance Code Review Issues Paper (September 2020)
kV	kilovolt
MWh	megawatt hours
NECF	National Energy Customer Framework
NER	National Electricity Rules
NER (NT)	National Electricity Rules as applied in the Northern Territory
Network provider	an entity holding a network licence granted by the Commission under the ER Act
NTERR	Northern Territory Electricity Retail Review
NTPSPR	Northern Territory Power System Performance Review
PWC	Power and Water Corporation
RBA	Reserve Bank of Australia
Retailer	an entity holding a retail licence granted by the Commission under the ER Act
Territory Generation	Power Generation Corporation, trading as Territory Generation

Final decision

In accordance with section 24(1) and (3) of the *Utilities Commission Act 2000* and regulation 2B of the Utilities Commission Regulations 2001, the Commission has decided to amend the Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels) (the Code) as detailed in this Final Decision document. The Final Decision outlines the Commission's reasoning for the amendments to the Code.

The Final Decision should be read in conjunction with the Draft Decision, which was published on the Commission's website in February 2023, however no changes have been made between the Commission's Draft Decision and Final Decision.

Below is a summary of the final decisions, set out by chapter.

Application of the Code (Chapter 2)

The Commission has decided to amend the Code to clarify that it only applies to an electricity entity to the extent that it provides generation services, network services, or retail services in the networks subject to network access legislation.

Guaranteed Service Level (GSL) scheme (Chapter 3)

The Commission has decided to amend the Code to:

- require the Commission to complete a review of Guaranteed Service Levels (GSL) scheme performance indicators, GSLs and GSL payment amounts at least 20 months before the start of a new regulatory control period for electricity networks
- amend Schedule 1 to make it explicit that planned network interruptions are excluded from duration and frequency based GSL performance indicators
- remove the keeping appointments GSL scheme performance indicator from Schedule 1 of the Code
- amend the 24 hour timeframe in the GSL target standard regarding the re-connection of existing premises to one business day
- adjust GSL payment amounts (rounded to the nearest 50 cents) to account for actual Darwin consumer price index (CPI), and then forecast inflation using the Australian Energy Regulator's (AER) methodology to calculate future GSL payment amounts for five years, and then apply an inflation adjustment of 2.5% for any remaining years until the end of the next regulatory control period (30 June 2029).

Reporting of historical data (Chapter 4)

The Commission has decided to amend the Code to clarify that reported historical data must be of a consistent methodology to the current reporting year's data.

Independent audit obligations (Chapter 5)

The Commission has decided to amend clause 6.2.4 of the Code to remove the requirement to provide a list of potential auditors.

Schedule 2 Generation services performance indicators (Chapter 6)

The Commission has decided to amend Schedules 2 and 7 of the Code to reflect the changes advised in the Commission's direction issued under clause 1.6 of the Code on 20 November 2018.

Schedule 3 Network services performance indicators (Chapter 7)

The Commission has decided not to amend the Code to:

- include additional metering obligations on network entities
- include any large-scale generation-related connection performance indicators for network entities.

Schedule 4 Retail services performance indicators (Chapter 8)

The Commission has decided to:

- add a definition for 'small business customer', amend the definition of 'residential customer' and include a new clause to provide additional clarification
- amend Schedule 4 of the Code to remove the requirement for retail entities to report on the number of customers by meter type in Table 4
- delete S.4.2.5(b) as it relates to the number of customers by meter type
- amend Schedule 4 of the Code to clarify that retail entities are to report both the total number of pre-payment meter self-disconnection events for all pre-payment meter customers in each reporting period and the total number of pre-payment customers self-disconnected
- amend Schedule 4 of the Code to clarify that debt and energy bill debt should be counted from the date a bill is due, rather than the date the bill is issued
- exclude customers with debt or energy bill debt of less than $10 from retail entities' reporting of debt and energy bill debt performance indicators under Schedule 4 of the Code.

Regional segmentation (Chapter 9)

The Commission has decided to:

- define the Darwin region for reporting segmentation purposes as the region able to be supplied by the Darwin 11 and 22 kilovolt (kV) network and the Katherine region for reporting segmentation purposes as the region able to be supplied by the Katherine 11 and 22 kV network
- amend the Code to remove the requirement for retailers to segment data by region for all relevant retail services performance indicators in Schedule 4, Table 4 of the Code other than those regarding pre-payment meters.

Correction of administrative errors (Chapter 10)

The Commission has decided to amend the Code to include the Code schedules in the table of contents and address several minor wording errors.

1 | Introduction

Background

In the Northern Territory, the Commission is responsible for promoting and safeguarding competition and fair and efficient market conduct or, in the absence of a competitive market, the simulation of competitive market conduct and the prevention of the misuse of monopoly power.

The Commission has, among others, the following functions:[1]

- to develop, monitor and enforce compliance with and promote improvements in standards and conditions of service and supply under the relevant industry regulation Acts
- to make, monitor the operation of, and review from time to time, codes and rules relating to the conduct or operations of a regulated industry or licensed entities under relevant industry regulation Acts.

The Commission is authorised to make a code relating to standards of service by licensed entities in the electricity supply industry[2].

Regulation 2B of the Utilities Commission Regulations 2001 states a code about standards of service may deal with the following:

- standards of service by licensed entities in the electricity supply industry
- performance measures for standards of service by licensed entities in the electricity supply industry
- payments to certain customers if specified standards of service are not met.

Accordingly, on 1 January 2006, the Electricity Standards of Service Code (ESS Code) came into effect. The objectives of the ESS Code were to:

- establish standards of service and performance measures in the electricity supply industry
- develop, monitor and enforce compliance with and promote improvement in standards of service by electricity entities in the electricity supply industry
- require electricity entities to have adequate systems in place to allow for regular reporting of actual performance in accordance with the ESS Code.

Additionally, the Guaranteed Service Levels Code (GSL Code) commenced on 1 January 2012. The objectives of the GSL Code were to establish:

- a GSL scheme providing for GSL payments to be made by a network provider to small customers where the supply of electricity and other related services does not meet the pre-determined GSLs
- a dispute resolution process for the GSL Code.

In 2017, the Commission undertook a significant review of the ESS and GSL codes and the two codes were merged into a single code (the Code). Following this initial review, the Commission committed to further reviews and updates to the Code, although these would occur as needed rather than there being a prescribed timeframe for regular review. Further, in 2018 the Commission issued a direction under clause 1.6 of the Code to address some anomalies and is aware of other issues.

On 16 September 2020, the Commission commenced its next review of the Code, publishing the Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels) Review Issues Paper (Issues Paper), and sought feedback from interested stakeholders. Responses were received from the following stakeholders:

[1] Section 6(1)(c) and (d) respectively of the *Utilities Commission Act 2000*.

[2] Section 24(1) and (3) of the *Utilities Commission Act 2000* and Regulation 2B of the Utilities Commission Regulations 2001.

- EDL NGD (NT) Pty Ltd (EDL)
- Eni Australia Limited (Eni)
- Epuron Pty Ltd
- Jacana Energy
- Power and Water Corporation (PWC)
- Territory Generation.

Given the wide-ranging feedback received from stakeholders and the need to address some matters as a priority, the Commission decided to address the more immediate regulatory issues and straightforward matters in its Draft Decision (stage 1 review of the Code). The Commission advised that it will undertake a further review of the Code in due course.

The Commission considered stakeholders' feedback in making its Draft Decision, which was published along with a draft amended Code on 17 February 2023. The Commission received responses from the following stakeholders regarding its Draft Decision:

- a group of researchers associated with the Australian National University (ANU)
- Jacana Energy
- Minister for Renewables and Energy.

The Commission notes that Jacana Energy's response to the Draft Decision advises that it has "reviewed the proposed amended EIP Code and has no further feedback." Further, the response from the Minister for Renewables and Energy does not raise any concerns with the Commission's Draft Decision.

For further information on the Electricity Industry Performance Code Review please visit the Commission's website at http://www.utilicom.nt.gov.au.

Purpose of this review

The Commission reviewed the Code to ensure its content and operation are of continued relevance and effectiveness for the electricity supply industry in the Territory.[3]

Terms of reference and scope of inquiry

The stage 1 review considered and addressed the known priority and straightforward issues listed below:

- a review of Schedule 1 (GSL Scheme) associated with the start of a new regulatory control period on 1 July 2024 for PWC's regulated electricity networks, which are regulated by the AER
- a review of Schedule 2 (Generation Services Performance Indicators) to address known issues currently dealt with through a direction issued by the Commission on 20 November 2018 under clause 1.6 of the Code
- a review of Schedule 7 (Definitions and Interpretation) to address known issues currently dealt with through a direction issued by the Commission on 20 November 2018 under clause 1.6 of the Code
- other time-critical and straightforward matters or gaps identified through the operation of the Code, in the annual Northern Territory Power System Performance Review (NTPSPR), annual Northern Territory Electricity Retail Review (NTERR) and stakeholder submissions.

[3] Section 24(9) of the *Utilities Commission Act 2000*.

Purpose of this paper

This paper sets out the Commission's amendments to the Code, following consideration of submissions to its February 2023 Draft Decision.

Timetable for review

The relevant timeframes for commencement of the amended Code are outlined below:

Action	Timing
Release of Final Decision to amend Code, including Notice of Variation in Gazette	8 June 2023
Amended Code commences	1 July 2023

2 | Application of the Code

Background

Clause 1.4.1 of the Code states the Code applies to electricity entities in the Northern Territory. Clause 1.4.2 of the Code provides further clarity stating to avoid doubt, the Code will only apply to an electricity entity to the extent that it provides generation services, network services, or retail services in the regulated network.

While the definition of 'electricity entity' in the Code is clear, the Commission noted in its Issues Paper that clarification may be needed about where the Code applies as the definition of 'regulated network' could be interpreted as an electricity network or power system in which any form of price regulation is applicable, such as those subject to an electricity pricing order, rather than only the Darwin-Katherine, Alice Springs and Tennant Creek networks.

The Issues Paper discussed the approach in the Electricity Retail Supply Code where the issue of application is defined through use of the term 'Network Access Legislation' with this defined as 'the legislation regulating connection to and use of electricity networks as in force in the Northern Territory from time to time, being the National Electricity (NT) Rules'. The National Electricity (NT) Rules are subsequently defined through reference to the relevant legislation.

The Commission's Issues Paper suggested a similar approach could be adopted in the Code to provide clarity on its application.

Stakeholder feedback in response to the Issues Paper was received from EDL and PWC regarding the application of the Code.

Both stakeholders supported amendments to provide additional clarification that the Code is only applicable to the Darwin-Katherine, Alice Springs and Tennant Creek networks (and associated power systems) with PWC stating that confusion exists among entities that provide generation, network and retail-related services outside of the Darwin-Katherine, Alice Springs and Tennant Creek power systems as to the application of the Code.

The Draft Decision proposed to amend the Code to clarify that it applies to an electricity entity to the extent that it provides generation services, network services, or retail services in the networks subject to network access legislation (currently the Darwin-Katherine, Alice Springs and Tennant Creek networks, and in Nhulunbuy, through Alcan Gove Pty Ltd's licence exemption conditions), through a revised definition for regulated network and new associated definitions.

Submissions

Following consultation on the Commission's Draft Decision, further stakeholder feedback was received in relation to the application of the Code, from the ANU researchers.

The ANU researchers' submission acknowledges that the Commission's proposed amendment is to formalise how the Code is already applied in practice, however raises concerns that the Code does not apply more broadly across the Territory, such as to isolated networks serving remote communities, which are operated by PWC via its subsidiary Indigenous Essential Services Pty Ltd (IES). The ANU researcher's submission argues the proposed amendment:

> *maintains extant disparities in those rights and protections afforded to customers residing in the major networks in the [Territory] compared to customers living in remote communities. Due to the distinctions embedded in the Code and in regulatory practice, remote customers have neither the benefits of a GSL scheme nor the transparency and procedural rights provided by retail performance reporting. Such benefits are only afforded to customers in the major networks. The effect of the Code is the maintenance of regulatory difference based on where people reside.*

The ANU researchers' submission goes on to suggest:

> *In practice the impacts of these regulatory disparities are unlikely to be trivial. Without performance reporting against indicators such as customer numbers, disconnections and involuntary 'self-disconnections', the visibility of energy insecurity in remote communities continues to be limited. There is an obvious need for improved reporting requirements in remote locations where [PWC] is the retailer, including the 72 remote communities and 66 outstations currently serviced by its subsidiary IES.*

The ANU researchers' submission encourages the Commission to consider expanding the application of the Code Territory-wide so that all residential customers can benefit from the rights and protections it provides, and suggests some barriers that may have been relied upon to differentiate reporting requirements between major and isolated networks, such as in relation to metering, are becoming incrementally redundant.

Commission's decision and reasons

The Commission acknowledges the concerns raised in the ANU researchers' submission regarding disparities in reporting requirements, and subsequent public visibility of potential issues and performance in the Territory between access-regulated networks and isolated or remote networks, such as those serviced by government-owned PWC's not-for-profit subsidiary IES. However, the Commission considers that this disparity is not based on 'where people reside,' but rather the difference in regulatory frameworks or supply models in place for these vastly different networks.

The Darwin-Katherine, Alice Springs and Tennant Creek networks are subject to a more prescriptive open-access framework, while the majority of (but not all) isolated or remote networks are supplied by IES under contract with the Territory Government. Noting the vast differences between the access-regulated networks and networks in remote communities, the Commission considers it may be appropriate for different regulatory frameworks or supply models to apply in the different networks, which is the current situation.

However, while the Commission is not privy to the terms and conditions of the contract between the Territory Government and IES, it would expect the contract to include adequate oversight, protections and standards of service requirements. Therefore, the Commission considers the relevant matters raised in the ANU researchers' submission are better brought to the attention of, and considered as appropriate by, the Territory Government. Accordingly, the Commission has written to the Minister for Essential Services to provide a copy of the ANU researchers' submission so that the Minister (and the Territory Government) is aware of the ANU researchers' views in order to help inform future Government policy decisions.

In terms of clarifying the application of the Code to the Darwin-Katherine, Alice Springs and Tennant Creek networks, the Commission agrees with stakeholder feedback that the Code should be clearer concerning its applicability.

Generally, it is intended the Code is applied to where network access legislation applies (currently the Darwin-Katherine, Alice Springs and Tennant Creek power systems); however, the Commission notes there is currently one exception, being Alcan Gove Pty Ltd's licence exemption for electricity supply operations in Nhulunbuy. Under the licence exemption Alcan Gove Pty Ltd is required to comply with aspects of the Code, including the GSL scheme, as if Alcan Gove Pty Ltd were licensed and provides network services and retail services to its electricity customers in the regulated networks. Any amendment to the Code concerning applicability must ensure this intentional condition in the licence exemption remains binding on Alcan Gove Pty Ltd.

Final decision

The Commission has decided to amend the Code to clarify that it applies to an electricity entity to the extent that it provides generation services, network services, or retail services in the networks subject to network access legislation (currently the Darwin-Katherine, Alice Springs and Tennant Creek power systems, and in Nhulunbuy, through Alcan Gove Pty Ltd's licence exemption conditions), through a revised definition for regulated network and new associated definitions.

Approved amendments:

Schedule 7 Definitions and interpretation

Electricity network	Has the meaning given in the ***ERA***
National Electricity (NT) Rules	see section 3(1) of the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
Network access legislation	The legislation regulating connection to and use of ***electricity networks*** as in force in the Northern Territory from time to time, being the ***National Electricity (NT) Rules***
Regulated network	An ***electricity network*** that is subject to ***network access legislation*** ~~price regulation by the ***AER*** or the ***Commission***~~. For the avoidance of doubt, the regulated network ceases at the electrical installation.

3 | Guaranteed Service Level (GSL) scheme

Periodic review of GSL scheme

Background

The previous GSL Code included a clause requiring the Commission to review the performance measures, GSLs and GSL payment amounts before the beginning of each regulatory control period; however, this clause was not included in the Code when it was established. Therefore, the Code does not include a 'trigger' to review the GSLs and GSL payment amounts.

Jacana Energy advised in its submission to the Issues Paper that review of GSL and GSL payments before each regulatory control period would ensure that GSL and GSL payments reflect the current market (and maintain the incentive towards ensuring expected service levels).

Further, PWC advised forecasting GSL payments is important for its submission to the AER for regulatory determinations and greater certainty on the structure and magnitude of GSL payments for each regulatory control period would be more efficient and enable more accurate forecasting. PWC also suggested a review of the GSL payments should consider the timing of its submission to the AER, which would likely result in a review timeframe of two years before the commencement of each new regulatory control period. This would mean a review for the next regulatory control period should commence in 2022.

The Draft Decision proposed to amend the Code to include a clause to review GSLs and GSL payment amounts before the beginning of each regulatory control period.

The Commission noted in the Draft Decision that the current GSL payment amounts are set in the Code until the end of 2023-24 (the end of the current regulatory control period for electricity networks, which is regulated by the AER).

Submissions

No submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

Consistent with the Draft Decision, the Commission considers a mandated review of GSL scheme performance indicators, GSLs and GSL payment amounts under Schedule 1 GSL Scheme before each new regulatory control period is needed, with a review to be completed at least 20 months before the end of each regulatory control period. This will provide PWC with a minimum of three months to finalise its regulatory proposal to the AER as it relates to the GSL scheme.

Final decision

The Commission has decided to amend the Code to require the Commission to complete a review of GSL scheme performance indicators, GSLs and GSL payment amounts at least 20 months before the start of a new regulatory control period for electricity networks.

<u>Approved amendments:</u>

4.7 Review of GSL Scheme

4.7.1 The ***Commission*** must complete a review of the ***performance indicators***, ***guaranteed service levels*** and ***GSL payment*** amounts in schedule 1 at least 20 months prior to the start of a new ***regulatory control period*** for electricity networks.

GSL performance indicators – planned network interruptions

Background

When the ESS and GSL codes were combined to make the Code in 2017, separate lists of exclusions were also combined and made consistent with the AER's Service Target Performance Incentive Scheme. Consequently, the list of exclusions in clause 7.2.3 of the Code does not include planned maintenance (or planned network interruption). While this may have been appropriate in the previous ESS Code-related provisions, an unintended consequence is that the GSL-related provisions in the Code may be interpreted as including planned maintenance in duration and frequency based GSLs.

Notably, in the Commission's Review of Options for Implementation of a Customer Service Incentive Scheme for Electricity Customers Final Decision (published on the Commission's website in 2010) the Commission discussed and explicitly stated that planned interruptions (when the relevant notice is given) are excluded from GSL payments relating to duration and frequency based GSLs.

A related potential issue is the definition of 'interruption' in the Code. Clause 4.1.3 of the Code states that if a network entity does not meet a GSL concerning a small customer it must pay that small customer the relevant GSL payment set out in Schedule 1. Schedule 1 of the Code lists four GSLs concerning the duration and frequency of interruptions, with 'interruption' defined as temporary unavailability or temporary curtailment of supply of electricity to a premise, but does not include unavailability or curtailment under the terms and conditions of that contract for the supply of electricity at that premise. As a contract for supply is at the discretion of the network entity and may include any type of outage, there is a possibility that all interruptions would be deemed excluded from the Code definition of 'interruption'. If this is the case, it is inconsistent with the intent of the GSL scheme.

Jacana Energy noted in its submission to the Issues Paper that the inclusion of planned maintenance in duration and frequency based GSLs would provide an incentive to ensure expected service levels and clear compensation for the inconvenience incurred from excessive planned maintenance.

Contrary to Jacana Energy, PWC advised it considers it reasonable to exclude planned maintenance from duration and frequency based GSLs for several reasons including that a GLS scheme is intended to encourage improvement in reliability for poorly served customers, and the inclusion of planned maintenance in the GSL scheme may provide a disincentive to performing maintenance and add complexity in reporting and defining types of planned maintenance.

In relation to whether the current Code definition of 'interruption' is appropriate, and if there is a possibility all interruptions could be excluded from GSL payments if the terms and conditions of the contract for supply should include all types of interruption, PWC was the only stakeholder to respond. PWC considers the definition and supporting clauses provide a clear definition of an 'interruption', noting that PWC does not consider a 'planned network interruption' as an eligible outage for the purposes of GSLs.

Nonetheless, PWC advised that it considers the definitions and use of terms for various types of 'interruption' more generally in the Code should be reviewed and made more consistent, as it has led to customer confusion around the eligibility of certain outages. PWC stated that 'network interruption', 'unplanned network interruption' and 'planned network interruption' have specific definitions, whereas 'interruption' does not, and the way the eligibility criteria is described in the Code does not align well with the definitions.

The Draft Decision proposed to amend the Code to make it explicit that planned network interruptions are excluded from duration and frequency based GSLs.

Further, the Draft Decision proposed to amend the definition of 'interruption' to ensure all interruptions could not be excluded from GSL payments through terms and conditions in a contract for supply of electricity to a premise.

Submissions

No submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

Consistent with the Draft Decision, The Commission has decided to continue the exclusion of planned maintenance from the GSL scheme, but with Code amendments to make it explicit that planned network interruptions are excluded from duration and frequency based GSLs.

Final decision

The Commission has decided to amend Schedule 1 to make it explicit that planned network interruptions are excluded from duration and frequency based GSL performance indicators.

Approved amendments:

Schedule 1, Table 1

Duration of a single ***unplanned network interruption*** ~~***interruption***~~

More than 12 ***hours*** and less than 20 ***hours***

More than 20 ***hours***

Frequency of ***unplanned network interruptions*** ~~***interruptions***~~

More than 12 ***unplanned network interruptions*** ~~***interruptions***~~ in a ***financial year***

Cumulative duration of ***unplanned network interruptions*** ~~***interruptions***~~

More than 20 hours of ***unplanned network interruptions*** ~~***interruptions***~~ in a ***financial year***

Schedule 7 Definitions and interpretation

Interruption	A temporary unavailability or temporary curtailment of the ***supply*** of electricity to a ***premises***~~, but does not include unavailability or curtailment in accordance with the terms and conditions of that contract for the **supply** of electricity at that **premises**~~.

GSL performance indicator – keeping appointments

Background

In response to PWC's submission to the Issues Paper, the Commission proposed in its Draft Decision to remove the keeping appointments performance indicator in Schedule 1 of the Code.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

In considering PWC's proposal, the Commission reviewed GSL schemes in other jurisdictions for relevant performance indicators and GSLs, and PWC's GSL reporting over recent years against the keeping appointments performance indicator.

While the Commission considers that other jurisdictions' GSL provisions provide greater flexibility than the Territory's current GSL scheme, as they allow for appointment windows, the costs are likely to outweigh the benefits of retaining or modifying the keeping appointments performance indicator and GSL in the Code. This is on the basis that PWC would need to invest in an appropriate system to enable compliance and reporting despite making few appointments with small customers that require a customer's attendance, noting the costs to comply with regulatory obligations ultimately flow to electricity customers (and tax payers through government's associated community service obligation to retailers).

Final decision

The Commission has decided to remove the keeping appointments GSL scheme performance indicator from Schedule 1 of the Code.

Approved amendments:

Schedule 1, Table 1

~~Keeping appointments:~~

~~— Within 30 minutes of the time agreed with the small customer~~

GSL target standard – time for establishing a connection

Background

Schedule 1 of the Code includes a GSL target standard for the time to re-connect an existing premises, which is within 24 hours of receipt by the network entity of a valid request for re-connection from the small customer.

The Code defines a business day as a day that is not a Saturday, Sunday or observed as a public holiday in the Northern Territory.

In response to a PWC submission to the Issues Paper, the Commission proposed in the Draft Decision to amend the timeframe for the GSL target standard regarding the re-connection of existing premises from 24 hours to one business day.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

In considering PWC's proposal, the Commission reviewed GSL schemes in other jurisdictions regarding reconnection performance indicators, and PWC's GSL reporting over recent years, among other things.

The Commission considers that while amending the timeframe from 24 hours to one business day would be a lowering of a standard, on review of the current standard against that in other jurisdictions and PWC's reasoning, the Commission supports PWC's suggestion. This is primarily on the basis that if PWC were to change its practices to meet the target standard of within 24 hours, regardless of weekends and public holidays, the additional costs would likely be material and would ultimately be borne by customers and taxpayers through higher network charges.

Final decision

The Commission has decided to amend the 24 hour timeframe in the GSL target standard regarding the re-connection of an existing premises to one business day.

Approved amendments:

Schedule 1, Table 1

Time for establishing a ***connection***:

> ***Re-connection*** of an existing premises – within ~~24~~ ~~***hours***~~ one ***business day*** of receipt by the ***network entity*** of a valid request for ***re-connection*** from the ***small customer***

GSL payment amounts

Background

Schedule 1 of the Code sets out GSL payment amounts that a network entity must pay eligible small customers when it does not meet the associated GSL. The GSL payment amounts are intended to be at a level that acknowledges the inconvenience customers experience due to interruptions associated with network performance, and they act as an incentive for the network entity to provide an appropriate level of service. Importantly, GSL payment amounts are not intended to provide insurance-style compensation for any loss or damage that a customer may suffer from an interruption, noting the costs for making GSL payments to relevant customers are ultimately borne by all customers (and taxpayers when prices to customers are capped by the government's electricity pricing order) through network charges.

Before 2019-20, GSL payment amounts were set and did not change or escalate each year. In 2017, when the Code was amended, the Commission's policy changed and GSL payment amounts were adjusted for inflation. However, the GSL payments were only set until the end of the 2023-24 financial year.

The 2023-24 financial year is the last year of the current regulatory control period for PWC's electricity networks business. PWC is currently preparing its final proposal to the AER for the next regulatory control period, which will need to include a provision for expected GSL payments.

Submissions

No submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

Consistent with its approach when developing the Code, the Commission considers that GSL payment amounts should adjust with inflation to ensure the amounts remain constant in real terms, thereby maintaining a sufficient level of acknowledgement of the inconvenience to relevant customers and an incentive for the network entity.

The Commission reviewed the approach adopted in the current Code to ensure it met the intent of maintaining the GSL payment amounts in real terms and provided certainty in determining whether it is suitable for the next regulatory control period. The Commission found that since the start of the regulatory control period, when a rate of 2.5% was applied (the mid-point of the Reserve Bank of Australia's [RBA] target band), inflation (as measured by Darwin CPI) was lower in the initial years, but increased and surpassed the 2.5% target, in recent years.

Further, to consider how its approach of continuing to maintain GSL payment amounts in real terms compares with payment amounts in other jurisdictions, the Commission considered GSL schemes in Queensland, South Australia, Victoria and Western Australia. While GSLs differ in each jurisdiction, meaning direct comparisons are not possible, the GSL payment amounts under the Commission's approach compare reasonably with the range of payments in other jurisdictions.

While it would be preferable for GSL payment amounts to reflect inflation each year, the Commission considers the benefits of simplicity and certainty provided by 'setting' GSL payment amounts with a provision for escalation over the five year regulatory control period outweigh the costs of undertaking an annual adjustment process. The Commission has decided, however, to include a step in its methodology to adjust for differences between the 'set' payment and what the payment would have been based on actual inflation during the previous regulatory period to ensure payment amounts are maintained in real terms over the long-term and from one determination period to another.

The following describes the Commission's updated methodology for determining GSL payments that will apply from 2023-25:

- first, GSL payment amounts are adjusted to account for actual Darwin CPI (June to June quarter) from when the rates were originally set (with the commencement of the GSL Code on 1 January 2012), making the June quarter 2012 the base year. This calculates payments in real terms until 2021-22
- second, in forecasting GSL payment amounts for future years (years in which actual Darwin CPI is not known), the Commission's methodology for the forecasting of inflation for the purposes of calculating GSL payment amounts aligns with the AER's methodology, as outlined in the AER's Final Position – Regulatory Treatment of

Inflation[4] (AER methodology). The AER methodology is used by the AER and network businesses that it regulates, including PWC.

The AER methodology includes applying a linear glide-path from the RBA's forecasts of inflation for years 1 and 2 to the mid-point of the RBA's inflation target band (2.5%) in year 5. Years 1 and 2 in the Commission's calculations equate to years 2022-23 and 2023-24 (that is, the final years in the Commission's current determination). The Commission's methodology applies a rate of 2.5% for any future years until the end of the next regulatory control period (30 June 2029). This methodology is outlined below in Table 1.

Table 1 GSL payment amount escalation methodology

Year 1 (Y1)	Year 2 (Y2)	Year 3 (Y3)	Year 4 (Y4)	Year 5 (Y5)	Subsequent years
RBA Y1 forecast (June to June)	RBA Y2 forecast (June to June)	$Y2 - \frac{(Y2 - Y5)}{3}$	$Y3 - \frac{(Y2 - Y5)}{3}$	2.5% (mid-point of RBA inflation target band)	2.5% (mid-point of RBA inflation target band)

While this calculation results in a revised amount for the GSL payments for 2022-23 and 2023-24, there will be no change in the payments for those years; they will remain as per the Commission's Determination for the 2019-20 to 2023-24 period. The GSL payment in the first year of the next regulatory control period (that is, 2024-25) will capture the adjustment for differences between the payments based on the determination and payment based on the RBA's current inflation expectation. As the RBA's current expectations are higher than the 2.5% mid-point used in the 2019-20 to 2023-24 Determination there is a substantive increase in payments between the last year of that Determination (2023-24) and the first year of the next regulatory control period (2024-25).

Final decision

The Commission has decided to adjust GSL payment amounts (rounded to the nearest 50 cents) to account for actual Darwin CPI, and then forecast inflation using the AER method to calculate future GSL payment amounts for five years, and then apply an inflation adjustment of 2.5% for any remaining years until the end of the next regulatory control period (30 June 2029).

[4] https://www.aer.gov.au/system/files/AER%20-%20Final%20position%20paper%20-%20Regulatory%20treatment%20of%20inflation%20-%20December%202020.pdf

Approved amendments:

Performance indicators		**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**
Duration of a single ***unplanned network interruption*** ~~***interruption***~~:							
More than 12 ***hours*** and less than 20 ***hours***	per event	$99.50	$112.50	$116.00	$119.00	$121.50	$125.00
More than 20 ***hours***	per event	$155.50	$175.50	$181.00	$185.50	$190.00	$195.00
Frequency of ***unplanned network interruptions*** ~~***interruptions***~~:							
More than 12 ***unplanned network interruptions*** ~~***interruptions***~~ in a ***financial year***	per ***financial year***	$99.50	$112.50	$116.00	$119.00	$121.50	$125.00
Cumulative duration of ***unplanned network interruptions*** ~~***interruptions***~~:							
More than 20 ***hours*** of ***unplanned network interruptions*** ~~***interruptions***~~ in a ***financial year***	per ***financial year***	$155.50	$175.50	$181.00	$185.50	$190.00	$195.00
Time for establishing a ***connection***:							
Re-connection of an existing ***premises*** – within ~~24 ***hours***~~ one ***business day*** of receipt by the ***network entity*** of a valid request for **re-*connection*** from the ***small customer***	per day late, up to a maximum of $300.00	$62.00	$70.00	$72.50	$74.00	$76.00	$78.00
New connection of a ***customer's premises*** (excluding ***connections*** requiring network extension or augmentation) – within 5 ***business days*** of receipt by the ***network entity*** of a valid electrical certificate of compliance from the ***small customer*****,** or as otherwise agreed with the ***customer***	per day late, up to a maximum of $300.00	$62.00	$70.00	$72.50	$74.00	$76.00	$78.00
Time for giving notice of ***planned interruptions***:							
At least 2 **business *days'*** notice prior to the commencement of the ***day*** upon which the ***planned interruption*** will occur		$62.00	$70.00	$72.50	$74.00	$76.00	$78.00
~~Keeping appointments:~~							
~~Within 30 minutes of the time agreed with the ***small customer***~~		~~$24.90~~					

4 | Reporting of historical data

Background

Clause 5.2 of the Code sets out the reporting obligations for retail, generator and network entities against relevant performance indicators. Clause 5.2.2 requires, among other things, that a report made under clause 5 of the Code about performance indicators include four years of historical data plus the reporting period data.

The clause is intended to ensure the Commission has a consistent (or comparable) series of historical data for each performance indicator and each reporting period to enable the Commission to meet its clause 5.5.1 (a) EIP Code obligation to publish an assessment of a report submitted under clause 5 of the Code.

Accordingly, if an entity's methodology for calculating a performance indicator has changed, the Commission expects the changed methodology to be applied not only to the current reporting period but also to the four years of historical data. If this does not occur, the differing methodologies will impair the Commission's ability to complete a reasonable or fair assessment of performance.

In response to a PWC submission to the Commission's Issues Paper, the Commission considered removing or amending the clause 5.2.2(c) requirement to include four years of historical data in a report submitted under clause 5.1 of the Code. The Commission proposed in its Draft Decision not to remove the requirement to provide four years of historical data, however proposed to amend the clause to clarify that reporting of historical data under clause 5.2.2(c) must be consistent with the methodology used for the reporting of reporting period data under clause 5.2.2.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission notes that since receiving PWC's submission to the Issues Paper, PWC provided historical data in its 2021-22 reporting which was updated for changes in methodology.

While it is acknowledged that some stakeholders may have difficulties in producing current year and historical data using a consistent methodology, the Commission considers the need and purpose are clear and the regulated entity must ensure its systems and business practices are developed to ensure compliance.

Based on informal feedback from some licensees, the Commission understands that some licensees were unaware of the obligation to provide four years of historical data plus the reporting period data under clause 5.2 of the Code or disagree with the need to provide historical data each year on the basis that the historical data has been provided before.

Regarding being unaware of the historical data reporting obligation, the Commission considers this should no longer be the case as all relevant entities completed an independent audit of 2019-20 compliance with reporting obligations in the Code under clause 6.2 of the Code during the 2021-22 financial year.

In many cases where an entity has had to change methodologies, it has been due to the entity's incorrect interpretation of what specific data is required to be reported in the Code. The Commission considers that a greater level of engagement with the Commission regarding an entity's reporting obligations, particularly where they are unsure of the interpretation of an obligation, would largely remove the need for an entity to change methodologies, and in turn provide a consistent time series of data, removing the challenges associated with retrospectively applying a different methodology.

The Commission considers the obligation for relevant entities to provide four years of historical data plus the current reporting period data is necessary; however, the Code may benefit from an amendment to make the obligation more explicit. Therefore, the Commission has decided to amend the Code to clarify that reported historical and current period data must be consistent in terms of the methodology used.

Final decision

The Commission has decided to amend the Code to clarify that the historical data to be reported must be of a consistent methodology to the current reporting year's data.

Approved amendments:

5.2.2 A report under this clause 5 must include:

(a) a ***responsibility statement***;

(b) relevant internal audit reports; and

(c) four years of historical ***data*** plus the ***reporting period data.***

5.2.2A The methodology used for the reporting of historical ***data*** under clause 5.2.2(c) must be consistent with the methodology used for the reporting of ***reporting period data*** under clause 5.2.2(c).

5 | Independent audit obligations

Background

To ensure compliance with the Code, electricity entities are required under the Code to undertake an independent audit at least once every three years for each performance indicator that the electricity entity is required to report against. Clause 6.2.4 of the Code states that an electricity entity must consult with the Commission about the scope of an audit required by clause 6.2.1 and a list of potential independent auditors before appointing an independent auditor.

In response to an EDL submission to the Issues Paper, the Commission proposed in the Draft Decision to amend the obligation to provide a list of potential auditors under clause 6.2.4 of the Code, with the nomination of a single preferred auditor considered by the Commission to be sufficient.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission considered EDL's submission to the Issues Paper and agrees a reasonable approach to ensuring the Commission is comfortable with an electricity entity's potential auditor is for the entity to propose one preferred auditor, rather than a list of potential independent auditors, with the Commission able to advise the entity to propose an alternative potential auditor if considered necessary.

Final decision

The Commission has decided to amend clause 6.2.4 of the Code to remove the requirement to provide a list of potential auditors.

Approved amendments:

6.2.4 An ***electricity entity*** must consult with the ***Commission*** in relation to the scope of an audit required by clause 6.2.1 and ~~a list of~~ its preferred potential independent auditor~~s~~ before appointing an independent auditor.

6 | Schedule 2 Generation services performance indicators

Background

On 20 November 2018, the Commission issued a direction under clause 1.6 of the Code to address several anomalies identified through generation licensees' reporting against Schedule 2 of the Code. The anomalies also existed in the former ESS Code and may have impacted the accuracy of data reported to the Commission.

The known anomalies are isolated to Schedule 2 and Schedule 7 of the Code and relate to the examples provided in S.2.4.4 Equivalent Partial Outage Hours, S.2.4.7 Equivalent Availability Factor and S.2.4.9 Equivalent Forced Outage Factor. Further, the definitions of 'unit derating for a generating unit' and 'unit derating value for a generating unit' may have been misleading, with these subsequently replaced with 'unit derating' and 'unit derating value' under the direction issued by the Commission on 20 November 2018.[5]

The Draft Decision proposed to amend Schedules 2 and 7 of the Code to reflect the changes advised in the Commission's direction issued under clause 1.6 of the Code on 20 November 2018.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission considers that Schedules 2 and 7 of the Code should be amended to address the identified anomalies consistent with that in the direction, noting no stakeholder concerns were raised on this matter in response to the Commission's Issue Paper or Draft Decision. This approach will make the reporting obligation clearer as all relevant information will be located in one instrument.

Final decision

The Commission has decided to amend Schedules 2 and 7 of the Code to reflect the changes advised in the Commission's direction issued under clause 1.6 of the Code on 20 November 2018.

<u>Approved amendments:</u>

Replace Schedules 2 and 7 with the revised schedules issued under the Commission's direction on 20 November 2018.

[5] https://utilicom.nt.gov.au/publications/correspondence-directions-and-notices/electricity-industry-performance-code-direction

7 | Schedule 3 Network services performance indicators

Metering and customer data

Background

In response to Jacana Energy's submission to the Issues Paper regarding additional metering obligations on network entities, the Commission proposed not to amend the Code in its Draft Decision.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission considered Jacana Energy's submission to the Issues Paper and while it agrees there is a lack of clarity on when the 'full' Chapter 7A metrology provisions of the NER (NT) will commence in the Territory, it decided not to amend the Code to include additional metering obligations on network entities.

The Territory Government has responsibility for the regulatory framework regarding metering in the Territory, including the timing for commencement of obligations on PWC as the Metering Data Provider, through its adoption of Chapter 7A of the NER (NT) and associated transitional arrangements. Any metering requirements retailers consider are needed to fill the gap between now and the commencement of the 'full' Chapter 7A of the NER (NT) is a policy decision for the Territory Government

Final decision

The Commission has decided not to amend the Code to include additional metering obligations on network entities.

Large-scale generation-related connections

Background

In response to a submission from Eni to the Issues Paper regarding large-scale generation-related connection performance indicators for network entities, the Commission proposed not to amend the Code.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission agreed with Eni in its Draft Decision that there are no performance indicators in the Code associated with new generator connection delays and acknowledged there have been significant delays in connecting new generation in the Territory. However, the Commission considers that obligations on network entities to report on large-scale generation-related connections are outside the scope of the Code, which predominately focuses on the standards of service provided to residential and small business customers.

Relevantly, the Commission's 2020-21 NTPSPR discusses challenges with connecting new large-scale generation in the Territory and publicly reports licensee feedback to the Commission about connection delays. Specifically, the 2020-21 NTPSPR stated that licensee feedback indicated the capacity of PWC Power Services and System Control to meet the demands of new connections, ongoing operational challenges and the large-scale transitions occurring in the Darwin-Katherine and Alice Springs power systems is potentially insufficient.

Final decision

The Commission has decided not to amend the Code to include any large-scale generation-related connection performance indicators for network entities.

8 | Schedule 4 Retail services performance indicators

Definitions – Small customer, residential customer and small business customer

Background

Under Schedule 4 of the Code, retailers must report on their performance concerning small customers under the AER (Retail Law) Performance Reporting Procedures and Guidelines (AER Guidelines) for various indicators, with small customers to be segmented by residential and small business customers. However, while Schedule 7 of the Code defines 'residential customers,' it is silent on the definition of a 'small business customer.' The AER Guidelines refer to the National Retail Law for its definitions of 'customer,' 'small customer,' 'residential customer' and 'small business customer,' which may not be relevant in the Territory.

Following a request by Jacana Energy for clarity on the definitions, the Commission provided advice that it considers a 'residential customer' to be a customer considered by the Electricity Pricing Order as a domestic customer, and therefore charged a domestic-related tariff, and consumes or is likely to consume less than 160 megawatt hours (MWh) per annum, and a 'small business customer' to be a customer considered by the Electricity Pricing Order as a commercial customer, and therefore charged a commercial-related tariff, and consumes or is likely to consume less than 160 MWh per annum', for reporting purposes.

The Commission's Draft Decision proposed to amend the Code to add a definition for 'small business customer,' change the definition of 'residential customer' and include a new clause to provide additional clarification.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission considered stakeholder feedback to the Issues Paper and on the basis that Jacana Energy had to seek clarity on the definitions to ensure appropriate reporting, and noting PWC is not opposed to making changes for clarity, has decided to amend the Code to include a definition of 'small business customer' and revise the definition of 'residential customer.' Further, the Commission has decided to include a new clause to provide additional clarification.

In terms of PWC's feedback to the Issues Paper that the Commission should consider maintaining alignment with the AER, the Commission considers it has done so to the extent that is appropriate for the Territory. Specifically, the obligation still points to the AER Guidelines and only deviates as necessary, such as definitions that are not appropriate due to regulatory frameworks or different market structures.

Final decision

The Commission has decided to add a definition for 'small business customer', amend the definition of 'residential customer' and include a new clause to provide additional clarification.

<u>Approved amendments:</u>

Schedule 4 Retail services performance indicators

S.4.2.3 Notwithstanding any requirements of the ***AER***, ***retail entities*** must, for the purpose of calculating:

<u>(a)</u> ***retail services performance indicators*** for this ***Code***, ~~a~~ ~~***retail entity***~~ ~~must~~ only include small customers that are taking (or likely to take less than) 160 megawatt ***hours*** of electricity from the ***distribution network*** during the ***reporting period***.

<u>(b)</u> ***AER retail services performance indicators*** that require segmentation by ***residential customers*** and ***small business customers***, apply the definition of residential customer and small business customer in this ***Code***.

Schedule 7 Definitions and interpretation

Residential customer	A ***small customer*** ~~***customer***~~ who purchases electricity principally for its own personal, household or domestic use at ***premises***.
Small business customer	A ***small customer*** who is not a ***residential customer***.

Performance indicator – Hardship program case studies

Background

As discussed above, Schedule 4 of the Code requires retailers to report on their performance concerning small customers in accordance with the AER Guidelines for various indicators. When the Code was being developed, the AER Guidelines included hardship program case studies as a performance indicator; however, it was optional and was subsequently removed from the AER Guidelines.

In response to Jacana Energy's submission to the Issues Paper, the Commission's Draft Decision proposed to remove the hardship program case studies performance indicator.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission considered Jacana Energy's proposal in its submission to the Issues Paper and agrees with its reasoning for removing the hardship program case studies performance indicator. Schedule 4 of the Code requires that reporting must align with the AER Guidelines and the current AER Guidelines do not include hardship program case studies thus making the inclusion in Schedule 4 redundant.

Final decision

The Commission has decided to amend Schedule 4 of the Code to remove the performance indicator 'Case studies'.

<u>Approved amendments:</u>

Schedule 4, Table 4

Topic	Performance indicator	AER / NT	Relevant Reporting Period	Segmentation
Hardship Program				
	~~Case studies~~	~~**AER**~~	~~**AER**~~	~~**Region**~~

Performance indicator – Number of customers by meter type

Background

Schedule 4 of the Code requires retailers to report the number of customers by meter type, and while this indicator appears under the heading of 'pre-payment meters', clause S.4.2.5 (b) provides additional information which includes that the number of customers by meter type should be categorised by meter functionality (unmetered, pre-payment meters, interval meters, accumulation meter, and other).

The Commission received consistent advice over several years from a retailer that reporting meter type data, other than for pre-payment meters, is difficult as the data is held by PWC. The only way the retailer can report the meter data is to ask PWC to provide it to them so that the retailer can report it to the Commission. While the Commission accepted the retailer's reasoning for not being able to report the meter data and provided associated exemptions from this reporting for several years, the Commission has not provided an ongoing exemption. This is on the basis that the obligation for retailers to report the number of customers by meter type would be reviewed as part of the Code review (this review).

In the National Electricity Market jurisdictions, the AER collects information annually from the network businesses it regulates through Regulatory Information Notices, which includes the Territory's PWC. This information is published on the AER's website and includes the number of meters by meter type (types 1- 6), which is further segmented by single phase, multi-phase, current transformer connected and direct connect meters.

The Draft Decision proposed to amend Schedule 4 of the Code to remove the requirement for retail entities to report on the number of customers by meter type.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission considered the feedback from Jacana Energy and PWC to the Issues Paper and while it agrees with PWC, that reporting of customers by meter type is not relevant to the performance of a network provider and is more relevant to retail services performance, the current Territory electricity market circumstances are such that the retailer does not hold or have easy access to the meter type data. This data is held by PWC as the network provider or as one of its many metering roles assigned to it under the NER (NT).

The Commission notes that retailers in other jurisdictions hold and use customer meter type data, as it assists in developing tailored and innovative tariffs for their customers, among other things. In the Territory however, meter data challenges coupled with the current lack of a wholesale electricity market and regulated maximum electricity tariffs for most customers means there is less ability or incentive to design or offer innovative tariffs, other than for high-consuming customers not protected by the electricity pricing order. Nonetheless, pricing structure and tariffs could change in the future and retailers will need to be prepared or risk losing their customers to other competitors.

While the Commission considers retailers should seek to gather and hold customer meter data as part of normal business, the Commission acknowledges the current difficulties in the Territory and notes the data is publicly available through the AER's reporting processes and the Code reporting obligation likely represents unnecessary duplication. Accordingly, the Commission has decided to amend Schedule 4 of the Code to remove the requirement for retail entities to report on the number of customers by meter type.

Final decision

The Commission has decided to:

- amend Schedule 4 of the Code to remove the requirement for retail entities to report on the number of customers by meter type in Table 4
- delete S.4.2.5(b) as it relates to the number of customers by meter type.

<u>Approved amendments:</u>

Schedule 4, Table 4

Topic	Performance indicator	AER / NT	Relevant Reporting Period	Segmentation
Pre-payment meters				
	~~Number of customers by meter type~~	~~NT~~	~~Quarterly~~	~~Meter type /~~ ~~**Region**~~

S.4.2.5 Additional information for Northern Territory performance indicators is provided below:

(a) Complaints – Hardship, is the total number of customer service complaints associated with customer hardship measures.

(b) ~~Number of customers by meter type is number of active customers on the last calendar day of the reporting period. Meters must be categorised as per functionality; including unmetered, pre-payment meters, interval meters, accumulation meters, and other.~~ Not used

Performance indicator – Total number of pre-payment meter customers self-disconnected

Background

Under Schedule 4 of the Code, retail entities are required to report on several pre-payment meter-related performance indicators, including the total number of pre-payment meter customer disconnections.

Through retail entities' reporting, and a submission from Jacana Energy, it has been identified there is ambiguity relating to the reporting of the total number of pre-payment meter customers self-disconnected performance indicator, which arises when considering the Code and the AER Guidelines.

The ambiguity is such that the performance indicator could be interpreted in one of two ways, being either the total number of self-disconnection events for each customer in each reporting period or the total number of customers self-disconnected in a reporting period regardless of the number of times each customer was self-disconnected.

The Commission proposed in the Draft Decision to amend Schedule 4 of the Code to clarify that retail entities are to report both the total number of pre-payment meter self-disconnection events for all pre-payment meter customers in each reporting period and the total number of pre-payment customers self-disconnected.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission agrees with Jacana Energy that there is ambiguity in the reporting obligation, noting the intent is that retail entities report the total number of pre-payment meter self-disconnection events for each customer in each reporting period. For example, if 10 customers were disconnected 10 times each during a reporting period, 100 disconnections would be reported.

However, the Commission also considers there may be value in reporting against the other interpretation of 'total number of pre-payment customers self-disconnected', noting this is a separate performance indicator in the AER Guidelines. Given Jacana Energy has advised that it can also report against this performance indicator, the Commission has decided to amend the Code to include it.

Final decision

The Commission has decided to amend Schedule 4 of the Code to clarify that retail entities are to report both the total number of pre-payment meter self-disconnection events for all pre-payment meter customers in each reporting period and the total number of pre-payment customers self-disconnected.

Approved amendments:

Schedule 4, Table 4

Topic	Performance indicator	AER / NT	Relevant Reporting Period	Segmentation
Pre-payment meters				
	Total number of PPM customers self-disconnected	**AER**	**AER**	**Region**
	Total number of PPM self-disconnection events	**AER**	**AER**	**Region**

Debt counting methodology

Background

In jurisdictions covered by the National Energy Customer Framework (NECF), the Commission understands some retailers report on debt-related performance indicators by calculating debt from the bill issue date, whereas some retailers calculate debt from the bill due date. The AER Guidelines are silent on this issue.

Following a request from Jacana Energy, and in the absence of clarity in the AER Guidelines, the Commission provided clarification to Jacana Energy that it expects debt to be calculated from the bill due date. While this addressed the immediate issue, the lack of clarity in the Code remains.

The Draft Decision proposed to amend Schedule 4 of the Code to clarify that debt and energy bill debt should be counted from the date a bill is due, rather than the date the bill is issued.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission agrees with Jacana Energy that there is ambiguity in the counting methodology for debt and that it should be clearer in Schedule 4 of the Code that the calculation of debt and energy bill debt is from the date a bill is due, rather than the date the bill is issued.

The Commission will consider defining debt to clearly distinguish between hardship debt and energy debt in the next stage of the Code review.

Final decision

The Commission has decided to amend Schedule 4 of the Code to clarify that debt and energy bill debt should be counted from the date a bill is due, rather than the date the bill is issued.

Approved amendments:

S.4.2.3 Notwithstanding any requirements of the ***AER***, ***retail entities*** must, for the purpose of calculating:

(a) ***retail services performance indicators*** for this ***Code***, ~~a **retail entity** must~~ only include small customers that are taking (or likely to take less than) 160 megawatt ***hours*** of electricity from the ***distribution network*** during the ***reporting period***.

(c) ***AER retail services performance indicators*** in relation to debt and energy bill debt, count debt from the date a bill is due to be paid.

Debt and energy bill debt – amounts less than $10

Background

In a submission to the Issues Paper, Jacana Energy advised there is no guidance in the Code or the AER Guidelines concerning the reporting of debt which would allow for only debt amounts greater than $10 to be reported. Jacana Energy stated the way it treats debt depends on the amount of debt held on an account, with debt action only taken in respect of debt greater than $10 (this applies to both hardship debt and energy bill debt).

Jacana Energy is concerned incorporating debtors owing less than $10 into reporting could result in a drop in the average debt reported and diminish the severity and significance of debt levels, thereby diminishing the significance of debt as a reportable retail services performance indicator.

The Commission proposed in the Draft Decision to amend the Code to exclude customers with debt or energy bill debt of less than $10 from retail entities' reporting of debt and energy bill debt performance indicators under Schedule 4 of the Code.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission's decision and reasons

The Commission agrees with Jacana Energy that there is no guidance in the Code and AER Guidelines regarding the exclusion of debt under a certain amount for reporting purposes.

Given the lack of guidance, the Commission assumes retailers in NECF jurisdictions, which report under the AER Guidelines and are used to benchmark Territory performance, are including any amount of debt, regardless of how low the amount. This means that if the Commission were to amend the Code to exclude the debt of less than $10, it may result in a misalignment of reporting with NECF jurisdictions and hinder comparisons.

However, notwithstanding the benefits of aligning Territory reporting with that of the NECF jurisdictions, the Commission considers Jacana Energy's reasoning has merit. Specifically, including debt of less than $10, which may remain outstanding but is not subject to debt action, is likely to skew and lower the usefulness of relevant performance indicators. On this basis, the Commission supports Jacana Energy's suggestion that the Code is amended to exclude customers with debt and energy bill debt of less than $10 from retail entities reporting under Schedule 4.

Final decision

The Commission has decided to amend the Code to exclude customers with debt or energy bill debt of less than $10 from retail entities' reporting of debt and energy bill debt performance indicators under Schedule 4 of the Code.

Approved amendments:

S.4.2.3 Notwithstanding any requirements of the ***AER***, ***retail entities*** must, for the purpose of calculating:

(a) ***retail services performance indicators*** for this ***Code***, ~~a~~ ~~***retail entity***~~ ~~must~~ only include small customers that are taking (or likely to take less than) 160 megawatt ***hours*** of electricity from the ***distribution network*** during the ***reporting period***.

(d) ***AER retail services performance indicators*** in relation to debt and energy bill debt, exclude customers with debt or energy bill debt of less than $10.

9 | Regional segmentation

Darwin and Katherine regions

Background

Many performance indicators that electricity entities are required to report against under the Code require segmentation by region. The Code requires electricity entities to segment the Darwin-Katherine power system into separate Darwin and Katherine regions, however, the regions or boundary between the two regions is not defined in the Code.

Following a request from Jacana Energy, the Commission advised Jacana Energy that for reporting purposes against Schedule 4 of the Code, the boundary between the Darwin and Katherine regions occurs between Manton Dam and Pine Creek, with customers able to be supplied by the Darwin 11 and 22 kV network classified as the Darwin region and customers able to be supplied by the Katherine 11 and 22 kV network classified as the Katherine region, noting the Commission understands the Darwin and Katherine 11 and 22 kV networks are not physically connected. While this addressed the immediate issue, the lack of clarity in the Code remains.

In its Draft Decision, the Commission proposed defining the Darwin region for reporting segmentation purposes as the region able to be supplied by the Darwin 11 and 22 kV network and the Katherine region for reporting segmentation purposes as the region able to be supplied by the Katherine 11 and 22 kV network.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Commission’s decision and reasons

Given there was no stakeholder objection to the Commission’s proposed definition for the Darwin and Katherine regions, the Commission has decided to progress with defining the Darwin and Katherine regions for reporting segmentation purposes as proposed in the Draft Decision.

Final decision

The Commission has decided to define the Darwin region for reporting segmentation purposes as the region able to be supplied by the Darwin 11 and 22 kV network and the Katherine region for reporting segmentation purposes as the region able to be supplied by the Katherine 11 and 22 kV network.

<u>Approved amendments:</u>

Schedule 7 Definitions and interpretation

Region	Includes the: • Darwin region, being the area where ***customers*** are able to be supplied by the Darwin 11 and 22 kilovolt ***distribution network***; • Katherine region, being the area where ***customers*** are able to be supplied by the Katherine 11 and 22 kilovolt ***distribution network***; • Tennant Creek region; and • Alice Springs region.

Regional segmentation of retail performance indicators

Background

Schedule 4 Retail services performance indicators requires retailers that provide services to small customers in the Darwin-Katherine, Alice Springs and Tennant Creek networks to report against various performance indicators, including payment difficulties and hardship, disconnections for non-payment and pre-payment meters. Retailers are required to segment their reporting against these indicators by region, including Darwin, Katherine, Alice Springs and Tennant Creek.

Jacana Energy indicated a preference in its submission to the Issues Paper for reporting for the whole of the Territory rather than by region for all retail performance measures. Jacana Energy stated the relatively low customer base within the Territory is such that a statistically significant sample size is not reached unless data is reported at the Territory level, particularly concerning debt. Further, Jacana Energy considers reporting at the Territory level provides a better comparison with relevant AER-regulated jurisdictions that report at a whole of jurisdiction level (state and territory) rather than by region.

In response to Jacana Energy's submission to the Issues Paper, the Commission proposed in the Draft Decision to amend the Code to remove the requirement for retailers to segment data by region for all relevant retail services performance indicators in Schedule 4, Table 4 of the Code other than about pre-payment meters.

Submissions

In a submission to the Draft Decision, in which the Commission proposed to no longer require retailers to segment data by region for all relevant retail services performance indicators other than about pre-payment meters, the ANU researchers supported the Commission's proposal in relation to regional segmentation for prepayment meter data.

The ANU researchers' submission also observes that while segmented data is currently required across all retail performance indicators, the Commission only reports data at the Territory level in its annual NTERR, and suggests in order to support increased visibility around prepayment meters, it would be valuable to make segmented data for prepayment meter performance indicators publicly available, either in the NTERR or elsewhere.

Commission's decision and reasons

The Commission considered Jacana Energy's feedback to the Issues Paper and agrees that data at the Territory level provides a better comparison with relevant AER-regulated jurisdictions. Relevantly, it is for this reason that the Commission has never compared regional outcomes to AER-regulated jurisdictions in its publications.

The Commission notes that regional data often show differences, particularly for payment difficulties and hardship, disconnections for non-payment and pre-payment meter-related outcomes, however, the differences are not likely related to a retailer's performance, but rather the demographic and economic differences between the regions. While it is important to understand these differences for reasons such as developing government policies, the Commission considers it inappropriate to require retailers to report regional segmentation data when Jacana Energy has the majority of customers in the Territory and its services are not region specific.

While the Commission does not generally use the lower level regional retail performance data to perform its functions, the Commission has noted in its public reports that historical and comprehensive data relating to pre-payment meters in the Territory is limited. Further, feedback from ANU researchers regarding the Commission's Electricity Retail Supply Code review is that retailers should monitor and report more data on pre-payment meters. As such, the Commission considers, at least for now, that regional segmentation should still be required for pre-payment meters.

The ANU researchers have taken this further in its latest submission, suggesting segmented data for prepayment meter performance indicators be made publicly available. The Commission notes that it is currently only required to publish an assessment of reporting under the EIP Code, not raw data, however it will consider whether it is possible, valuable or appropriate to provide additional segmentation (or raw data) in relation to pre-payment meter data as part of future editions of the NTERR.

Final decision

The Commission has decided to amend the Code to remove the requirement for retailers to segment data by region for all relevant retail services performance indicators in Schedule 4, Table 4 of the Code other than about pre-payment meters.

10 | Correction of administrative errors

Background

The Commission proposed to amend the Code in the Draft Decision to include Schedules 1 to 7 in the table of contents, and to address several minor wording errors that had been identified throughout the Code as part of the review.

Submissions

No further submissions were received in response to the Draft Decision regarding this matter.

Final decision

The Commission has decided to amend the Code to include the Code schedules in the table of contents and address several minor wording errors.