Proposed electricity industry performance indicators

An independent review of performance indicators proposed to be used in the Northern Territory

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ACIL Tasman

Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 4, 114 William Street
Melbourne VIC 3000
Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001
Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 2, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601
Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005
Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
GPO Box 4670
Sydney NSW 2001
Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Jeremy Tustin
Telephone (03) 9604 4411
Mobile (0421) 053 240
email j.tustin@aciltasman.com.au

Contributing team members

Marianne Lourey

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Executive summary

The Utilities Commission (the Commission) is the independent industry regulator for the Northern Territory (the Territory). It has various responsibilities in the energy, water and sewerage industries in the Territory, including regulating electricity generators and transmission and distribution networks in the Darwin-Katherine, Alice Springs and Tennant Creek regions.

With retail contestability now in place for all customers, the original Electricity Service Standards Code is now partially redundant. The Commission has been consulting on replacing it with the "Northern Territory of Australia Electricity Standards of Service Code" (the draft Code).

Through the draft Code, the Commission proposes to adopt a number of performance indicators.

These indicators were described in the Commission's consultation paper of 15 May 2012 (consultation paper). They are also described in the draft Code.

The consultation paper contained written descriptions of the performance indicators along with informal formulae. The draft Code expresses the performance indicators as formal mathematical formulae with little or no written description.

The Commission engaged ACIL Tasman to review the performance indicators as expressed in the consultation paper and the draft Code and address the following two questions in relation to each:

1. Are the performance indicators consistent with generally accepted industry practice?
2. Do the performance indicators in the draft Code reflect those in the consultation paper?

We found that there were some errors either in the way that the performance indicators were expressed in the draft Code or in the way that terms were defined. Aside from these errors, our view is that the definitions of the proposed performance indicators are generally consistent accepted industry practice and that they are consistent as between the consultation paper and the draft Code.

In some cases the formulae in the code could be simplified without changing their meaning. Where this is possible we recommend that it be done. This report contains a consolidated list of proposed formulae for the Commission's proposed performance indicators.

The Commission proposes that certain performance indicators in the network sectors should be calculated on both an unadjusted and an adjusted basis to account for matters beyond the relevant network operator's control. This is not uncommon in the industry, though the particular definition proposed by the Commission is open to interpretation in some areas. In this area consistency will depend on how certain terms are interpreted.

1 Introduction

The Utilities Commission (the Commission) is the independent industry regulator for the Northern Territory (the Territory). It has various responsibilities in the energy, water and sewerage industries in the Territory. Relevantly for this review, those responsibilities include regulating electricity generators and transmission and distribution networks in the Darwin-Katherine, Alice Springs and Tennant Creek regions.

Electricity supply in the Territory is characterised by Government-owned and vertically integrated generation, transmission and distribution networks.[1] Power and Water Corporation (PWC) is the monopoly operator of electricity networks in the above three regions and either owns or otherwise controls all electricity generation in the Territory.[2]

Much of the Commission's current work stems from the Territory Government's approval, in 2009, of a reform program to strengthen regulatory oversight of the regulated industries (including electricity) in the Territory. The Commission's projects under that reform program are wide ranging. They include a review of the Electricity Standards of Service Code for the Territory, which was first adopted in the Territory in 2005 under the Electricity Service Standards Code (original Code).

With retail contestability now in place for all customers, the original Code is now partially redundant. The Commission is in the process of replacing it and has been consulting on replacing it with "Northern Territory of Australia Electricity Standards of Service Code" (the draft Code).

The draft Code would apply to all regulated electricity generators, transmission and distribution network businesses, and electricity retailers. It would not apply to Independent Power Producers.

The draft Code's objectives are to:

1. establish performance target standards in the electricity supply industry
2. monitor and enforce compliance with standards of service
3. ensure that electricity industry participants have systems in place to allow regular reporting of their performance.

1 Until recently, retail was also entirely Government owned, though a retail licence was issued to a private sector retailer in February 2011.

2 PWC owns the vast majority of generation in the territory and buys the electrical output from, and supplies fuel to, those generators that it does not own.

Through the draft Code, the Commission proposes to adopt a number of performance indicators.

These indicators were described in the Commission's consultation paper of 15 May 2012 (consultation paper).

The consultation paper contained written descriptions of the performance indicators along with informal formulae. The draft Code expresses the performance indicators as formal mathematical formulae with little or no written description.

The purpose of this report is to address the following two questions in relation to the performance indicators for the generation, transmission and distribution sectors[3] (the Commission's questions):

1. Are the performance indicators consistent with generally accepted industry practice?
2. Do the performance indicators in the draft Code reflect those in the consultation paper?

To address these questions, we consider whether, for each performance indicator:

- the definition in the draft Code corresponds to the generally accepted definition of that performance indicator
- the mathematical description in the draft Code corresponds with the written and mathematical description in the consultation paper.

The first item goes to whether the performance indicator is consistent with generally accepted electricity industry standards.

The second item goes to the question of consistency between the consultation paper and the draft Code. We have compared the mathematical expression of each performance indicator in the draft Code with the hybrid written and mathematical description in the consultation paper. We have also sought to identify any errors or ambiguities that may exist in the formulae in the draft Code.

In some cases the formulae in the draft code could be simplified without changing their meaning. Where this is possible we have recommended that it be done.

This review is limited to the performance indicators as they were proposed in the consultation paper. It does not extend to include a review of the appropriateness of those indicators.

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[3] The consultation paper included performance measures for the retail sector but these are outside the scope for this report.

Further, some of the indicators will have performance targets, which have not yet been set. This review does not consider the target service levels or the means by which they are to be set.

Finally, this review does not include the customer service performance indicators.

The remainder of this report is structured as follows.

Chapter 2 deals with the System Average Interruption Duration and Frequency Indices. The Commission proposes to apply these two performance indicators to the generation, transmission and network sectors. Our review of these indicators is applicable to all three sectors.

Chapter 4 discusses the Commission's proposed approach to adjusting raw data to account for network outages caused by events that are beyond the network operator's reasonable control. This approach applies to many of the performance indicators for the network sectors.

The remaining chapters deal with the performance indicators that the Commission proposes to apply to one sector or another. Specifically:

Chapter 5 deals with performance indicators for the generation sector.

Chapter 6 deals with performance indicators for the transmission sector.

Chapter 7 deals with performance indicators for the distribution sector.

Chapter 8 provides a summary of our recommendations.

2 Background – electricity sector performance reporting in Australia

The electricity sector comprises four sectors, namely generation, transmission, distribution and retail. In the Territory, these sectors are vertically integrated and owned by Government. In the National Electricity Market (NEM) States[4] the sectors are functionally separated and characterised by varying levels of public and private ownership. In Western Australia the Government owns businesses in each sector, but the generation and network sectors are structurally separated.

Performance reporting varies by sector and also to reflect the different ownership arrangements in different jurisdictions.

For the most part, the generation sector in the NEM is not subject to performance reporting. While some statistics may be compiled, individual electricity generators are not required to meet particular performance requirements.

Generators are required to meet a range of performance requirements as set out in the National Electricity Rules, but these are different types of performance measures to this in the draft Code.

This is equally true at the level of individual power stations as for companies that own several power stations and for NEM regions. The NEM is subject to the reliability standard, which requires that unserved energy should not exceed 0.002 per cent per annum. However, this does not apply to individual generators. We note that the Commission has considered the possibility of introducing a similar reliability standard for the Territory, and has decided that the draft Code is not the appropriate vehicle for doing so.

Rather than being subject to performance reporting regimes, generators are exposed to competitive forces. They are free to perform as well, or as poorly, as they choose, though only those that perform well can expect to be profitable.

For this reason, the approach to performance reporting that is generally accepted in the generation sector is less well defined.

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4 These are Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia.

We have taken some guidance from the Australian Energy Market Operator's (AEMO) approach to reporting of forced outages by generators.[5]

By contrast, the network sectors in the NEM are subject to a range of performance criteria. These include reporting of performance indicators as well as Guaranteed Service Level regimes and the Australian Energy Regulator's Service Target Performance Incentive Scheme.

To standardise reporting of performance indicators for network sectors and allow for comparison between jurisdictions, the Steering Committee on National Regulatory Reporting Requirements (SCONRRR) published a paper in March 2002 describing the way that certain measures of performance should be calculated and reported. That report remains the basis of jurisdictional reporting of electricity network performance. [6]

The Institute of Electrical and Electronic Engineers also maintains a reporting standard, known as IEEE 1366, that sets out methodologies for calculating distribution performance indicators. IEEE 1366 was last updated on 31 May 2012.

In the Transmission sector additional guidance is provided by the Australian Competition and Consumer Commission's "Statement of principles for the regulation of transmission revenues" (ACCC statement of principles).[7]

Between them, we take IEEE 1366 and the SCONRRR paper to be representative of generally accepted industry practice insofar as electricity network performance reporting is concerned in the distribution sector. In the transmission sector we rely on these two documents along with the ACCC statement of principles.

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5 See AEMO, 'Guidebook for Forced Outage Data Reporting", available from www.aemo.com.au

6 The report also related to the retail sector, but that is beyond the scope of this review.

7 See www.accc.gov.au

3 Reliability performance indicators – SAIDI and SAIFI

This chapter provides a review of the Commission's proposal to use the following reliability performance indicators:

- System Average Interruption Duration Index (SAIDI) as a measure of the duration of interruptions experienced by customers
- System Average Interruption Frequency Index (SAIFI) as a measure of the frequency of interruptions experienced by customers.

The Commission has proposed to use these two indicators in each of the three sectors of the electricity industry. In the two network sectors it has proposed to calculate them on both an unadjusted and an adjusted basis. Therefore, these two indicators account for ten of the 33 indicators reviewed in this report.

SAIDI and SAIFI are widely used in monitoring performance of electricity networks. In Australia they form part of the standard SCONRRR reporting by each jurisdiction. They are also defined in standard IEEE 1366 (2012) and its predecessors.

This chapter provides a discussion of SAIDI and SAIFI as they are proposed to be applied to all three levels of the electricity industry in the Territory. Section 3.1 provides a discussion of SAIDI. Section 3.2 provides a discussion of SAIFI.

3.1 SAIDI

SAIDI measures how long customers, on average, are without supply during a reporting period. There are two inputs:

- the total length of time, in minutes, of all interruptions during a reporting period
- the number of customers supplied during that time.

As the total length of interruptions on a network increases, SAIDI increases (for a given number of customers). Conversely, as the total number of customers increases, SAIDI decreases (for a given total length of interruption).

The first step in our review was to ascertain the meaning of SAIDI as is generally accepted in the industry. This is discussed in section 3.1.1.

The next step was to consider whether the definition in the consultation paper and the draft Code are consistent with one another and with the generally accepted definition. The Commission's two definitions are discussed in sections 3.1.2 and 3.1.3 respectively.

3.1.1 The generally accepted meaning of SAIDI

SAIDI is widely used. Along with SAIFI, it is the basis of network performance reporting in each Australian jurisdiction.

SAIDI was defined by SCONRRR in its 2002 report as: [8][9]

> the sum of the duration of each sustained customer interruption (in minutes) divided by the total number of distribution customers… [excluding] momentary events.

IEEE 1366 defines SAIDI as

> The total duration of interruption for the average customer during a predefined period of time…Mathematically:

$$SAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption}{Total\ Number\ of\ Customers\ Served}$$

Between them, the SCONRRR report and IEEE 1366 form the basis of network performance reporting around Australia, so this definition of SAIDI can reasonably be taken as indicative of generally accepted electricity industry practice.

3.1.2 Consultation paper definition of SAIDI

The consultation paper defines SAIDI five times as follows:

1. generation SAIDI
2. transmission unadjusted SAIDI
3. transmission adjusted SAIDI
4. distribution unadjusted SAIDI
5. distribution adjusted SAIDI

Other than the distinction between 'adjusted' and 'unadjusted', the five definitions of SAIDI are the same. This section discusses this common, underlying calculation. The Commission's proposal that performance indicators should be calculated on an 'adjusted' and 'unadjusted' basis is discussed in section 4.

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8 Utility Regulators Forum , March 2002, "National regulatory reporting for electricity distribution and retailing businesses", p.6 , available at http://www.accc.gov.au/content/index.phtml/itemId/332190

9 Similarly to the Commission's proposal that the network sectors should report certain performance indicators on both an adjusted and unadjusted basis, SCONRRR defines three 'levels' of reporting that distinguish between planned, unplanned and 'normalised' interruptions. See chapter 4 for details.

The consultation paper defines SAIDI as:[10]

> "…the length of time that the average customer was without supply due to [generation outages or transmission or distribution related events]. Interruption is defined as a network outage that results in a temporary unavailability or temporary curtailment of supply to customers by the relevant network and excludes Momentary Average Incident Frequency Incident events. The calculation is:
>
> SAIDI=Sum(Customer Minutes$_i$)/Sum(Customer$_i$)"

Our view is that the written description of unadjusted SAIDI in the consultation paper corresponds with the description provided by SCONRRR and IEEE 1366. Importantly we note that both the Commission and SCONRRR calculate the length of duration experienced by the average customer excluding momentary incidents, and that these are defined as incidents lasting less than one minute.

However, we note that the consultation paper describes SAIDI as the System Average *Incident* Duration Index, rather than *Interruption* Duration Index. We understand that this is a typographical error.

3.1.3 Draft Code SAIDI formula

The draft Code defines SAIDI using equation (1):[11, 12]

$$SAIDI\ adjusted = \frac{\sum_{i=1}^{n} MOSI_i}{\sum_{i=1}^{n} CS_i} \tag{1}$$

where:

$\sum$MOSI	is the duration for all interruptions expressed in minutes
$\sum$CS	is the sum of customers supplied
i	appears not to have been defined

Our view is that the SAIDI formula in the draft Code contains errors in the way it is expressed and that the definition of customer could be improved. These two issues are discussed in turn below.

In addition, the definition of generation outage in the draft Code includes outages with a duration of less than one minute. This definition is used in the SAIDI calculation for the generation sector (only). Therefore, for the generation sector, the definition of SAIDI is inconsistent with the network sectors. It is, however, consistent with the consultation paper, which was silent on the question of momentary outages for generation SAIDI. It is not clear

10 Discussion paper paragraphs 3.95 (transmission) and 3.102 (distribution). The written definition for the generation sector in paragraph 3.82 is brief, but consistent with this meaning. The mathematical description for all three is the same.

11 This refers to unadjusted SAIDI, which is the indicator that matches SCONRRR's definition. Adjusted SAIDI changes the definition of interruptions to exclude a subset.

12 The draft code also includes a single unnecessary bracket in the denominator. We have assumed that this is a typo and disregarded it.

whether the Commission intended generation SAIDI to include momentary outages, but we expect not.

Our proposed solution to them is to alter the SAIDI formula as shown in chapter 8.

Errors in expression

While the formula is clearly intended to correspond with the written description, the draft Code does not contain definitions of all of the terms used in the formula. This introduces ambiguity.

In particular, the subscript '*i*' is not defined.[13]

The interpretation that appears to fit most closely with how the equation is presented is that the subscript '*i*' is intended to define a particular network or power system. If so, the summation operators for both MOSI and CS are redundant. Each network has only one total MOSI and one CS, so there is nothing to sum. With this interpretation, the subscript *i* should also be on the SAIDI term itself. If this is the intention, it would be sufficient to define SAIDI as shown in equation (2).

$$SAIDI_i = \frac{MOSI_i}{CS_i} \tag{2}$$

where, for all networks *i*:

MOSI is the total duration for all interruptions on network (or power system) *i*, expressed in minutes

CS is the total number of customers supplied by network (or power system) *i*

However, this approach would be inconsistent with the approach taken in IEEE 1366 and by SCONRRR.

An approach that would be more consistent with the way SAIDI is applied elsewhere would be to use *i* to define an individual interruption.

In this case, $MOSI_i$ would refer to the number of minutes that *each* interruption lasted. The summation operator is required and the numerator of equation (1) appears correct.

However, if '*i*' is intended to define individual interruptions, then its use in the denominator of the calculation is incorrect. With this meaning of '*i*' the denominator requires that the number of customers is summed across incidents.

13 We also note that neither MOSI nor CS is defined explicitly. We have assumed that these are intended to mean "Minutes Of Customer Interruption" and "Customers Supplied" respectively.

Summing customers across the '*i*' incidents implies that SAIDI should be calculated by reference to only the number of customers affected by each interruption. This is inconsistent with the Commission's written description of SAIDI in the consultation paper and with the definitions of SCONRRR and in IEEE 1366. These are all clear that SAIDI should be averaged across all customers, not just those who experienced an interruption.

Definition of customers

The second problem with the expression of SAIDI in the draft code arises from the definition of customer.

The draft Code provides that a customer is defined as per section 4 of the *Electricity Reform Act 2000* (ERA). According to the ERA:[14]

> "customer" means a person who receives, or wants to receive, a supply of electricity for final consumption and includes:
>
> a) the occupier for the time being of a place to which electricity is supplied;
>
> b) where the context requires – a person seeking an electricity supply; and
>
> c) a person of a class declared by the Regulations to be customers.

Clause 2, section 1.2.5 of the draft Code makes it clear that the number of customers (and other data) used to calculate performance indicators must "correspond with the relevant reporting period." However, this definition stops short of stating how, or when, customers should be counted during the reporting period.

While this may be unnecessary for the purposes of the ERA, it is important for calculating performance indicators. Customers could be counted at a 'point in time', such as the beginning or end of a year, or in the middle of the year. Alternatively, the average number of customers supplied over a year could be calculated.

Depending on which definition is applied, SAIDI will be different. If customer numbers are growing then, given a total length of interruption, using end of year numbers will produce a smaller value for SAIDI than using beginning of year numbers. If customer numbers are falling, the reverse is true.

If different businesses or power systems count their customers differently, the performance indicators they produce may not be directly comparable with one another, especially for smaller power systems.

The SCONRRR report states that[15]:

> The number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period.

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14 *Electricity Reform Act,* s.4

15 Utility Regulators Forum *op cit* p.6

This is made explicit in the Victorian Electricity Distribution Code, which defines SAIDI as follows:[16]

> **SAIDI** means the 'System Average Interruption Duration Index' which is the total minutes, on average, that a **customer** could expect to be without electricity over a specific period of time, calculated as the sum of the duration of each **customer interruption** (in minutes), divided by the total number of **connected customers** averaged over the year.

Importantly, it refers to the average of number of customers connected at the beginning and end of the reporting period.

Our view is that the definition of SAIDI would be improved if there was an explicit requirement that SAIDI should be calculated by reference to the average number of customers over the relevant period. Using this approach would maximise the extent to which the Territory's performance indicators are consistent with those used in other jurisdictions and ensure comparability within the Territory over time.

3.2 SAIFI

SAIFI measures how often customers, on average, are without supply during a reporting period. There are two inputs:

- the total number of supply interruptions during a reporting period
- the number of customers supplied during that time.

As the total number of interruptions on a network increases, SAIFI increases (for a given number of customers). Conversely, as the total number of customers increases, SAIFI decreases (for a given number of interruptions).

The first step in our review was to ascertain the meaning of SAIFI as it is generally accepted in the industry. This is discussed in section 3.2.1.

The next step was to consider whether the definitions in the consultation paper and the draft Code are consistent with one another and with the generally accepted definition. The Commission's two definitions are discussed in sections 3.2.2 and 3.2.3 respectively.

3.2.1 The generally accepted definition of SAIFI

As discussed in section 3.1 above, SAIFI is widely used. Along with SAIDI, it is the basis of network performance reporting in each Australian jurisdiction.

SAIFI was defined by SCONRRR in its 2002 report as the: [17][18]

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[16] Electricity Distribution Code (Victoria) version 6, January 2011, clause 19, available at www.esc.viv.gov.au

[17] Utility Regulators Forum , March 2002, "National regulatory reporting for electricity distribution and retailing businesses", p.6 , available at http://www.accc.gov.au/content/index.phtml/itemId/332190

> Average number of times a customer's supply is interrupted per [reporting period].

IEEE 1366 defines SAIFI as

> How often the average customer experiences a sustained interruption over a predefined period of time…Mathematically:
>
> $$SAIFI = \frac{\sum Total\ Number\ of\ Customers\ Interrupted}{Total\ Number\ of\ Customers\ Served}$$

Between them, the SCONRRR report and IEEE 1366 form the basis of network performance reporting around Australia, so this definition of SAIFI can reasonably be taken as indicative of generally accepted electricity industry practice.

3.2.2 Consultation paper definition of SAIFI

As with SAIDI, and as discussed in section 3.1.2 above, the consultation paper defines SAIFI five times.

Other than the distinction between 'adjusted' and 'unadjusted', the five definitions of SAIFI are the same. This section discusses the common, underlying calculation. The Commission's proposal that performance indicators should be calculated on an 'adjusted' and 'unadjusted' basis is discussed in section 4.

The consultation paper defines SAIFI as:[19]

> "…the number of occasions that the average customer was without supply due to [generation outages of transmission or distribution related events]. The calculation is:
>
> SAIFI=Sum($Outage_i$)/Sum($Customer_i$)"

Our view is that the written description of SAIFI in the consultation paper corresponds with the description provided by SCONRRR and IEEE 1366.

We note that the consultation paper describes SAIFI as the System Average *Incident* Frequency Index, rather than the System Average *Interruption* Frequency Index. We understand that this is a typographical error.

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[18] Similarly to the Commission's proposal that the network sectors should report certain performance indicators on both an adjusted and unadjusted basis, SCONRRR defines three 'levels' of reporting that distinguish between planned, unplanned and 'normalised' interruptions.

[19] Discussion paper paragraphs 3.95 (transmission) and 3.102 (distribution). The written definition for the generation sector in paragraph 3.82 is brief, but consistent with this meaning. The mathematical description for all three is the same

3.2.3 Draft Code SAIFI formula

The draft Code defines SAIFI using equation (1):[20,21]

$$SAIFI\ adjusted = \frac{\sum_{i=1}^{n} SI_i}{\sum_{i=1}^{n} CS_i} \tag{3}$$

where:

∑SI	is the total number of interruptions
∑CS	is the total number of customers supplied
i	appears not to have been defined

Our view is that the SAIFI formula in the draft Code contains the same errors as the SAIDI formula. That is, there are errors in its expression and the definition of customer could be improved. The detail of these two issues is discussed in relation to the SAIDI formula above.

In addition, the definition of generation outage in the draft Code includes outages with a duration of less than one minute. This definition is used in the SAIFI calculation for the generation sector (only). Therefore, for the generation sector, the definition of SAIFI is inconsistent with the network sectors. It is, however, consistent with the consultation paper, which was silent on the question of momentary outages for generation SAIFI. It is not clear whether the Commission intended generation SAIFI to include momentary outages, but we expect not.

The formula used to define SAIFI in the draft Code is also more complex than necessary, which leads to the risk of misinterpretation.

Our proposed solution to these is outlined in chapter 8.

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20 This refers to unadjusted SAIDI, which is the indicator that matches SCONRRR's definition. Adjusted SAIDI changes the definition of interruptions to exclude a subset.

21 The draft code also includes a single unnecessary bracket in the denominator. We have assumed that this is a typo and disregarded it.

4 Adjusted and unadjusted performance indicators

The other chapters of this report relate to the underlying calculation of the various performance indicators the Commission proposes to apply to the generation, transmission and distribution sectors.

For the transmission and distribution sectors (only) the Commission has proposed that certain performance indicators should be calculated on both an unadjusted and adjusted basis.

The consultation paper explained that certain events would be excluded from relevant performance indicators when these are calculated on an adjusted basis. This would apply to events seen as being beyond the reasonable control of the network provider whose performance is being measured. Unadjusted performance indicators would include these events.

The events listed in the consultation paper as giving rise to an adjustment were:

- load shedding due to generation shortfall
- a network outage caused when the System Controller exercised any function or power it may have under an applicable law or code
- a network outage resulting from a direction by police of other authorised person, as long as the direction was not precipitated by the network provider's failure to comply with any applicable law or code
- a traffic accident
- an act of vandalism
- a natural event identified as a statistical outlier using the IEEE 2.5 beta method (described below) if the Commission has given its approval to the exclusion
- an interruption caused by a customer's electrical installation or its failure.

The draft Code defines the same list of events as being beyond the network provider's control.

Therefore, the Commission's approach to defining adjusted and unadjusted indicators is consistent as between the consultation paper and the draft Code.

The question that remains for this report is whether that approach is "consistent with generally accepted industry practice".

By defining the adjusted data set, the Commission is distinguishing between interruptions that are attributable to the actions of the network operator and those that were beyond its reasonable control.

Standard SCONRRR reporting requires that relevant performance indicators are reported on four different bases. The bases are defined in SCONRRR's Table 2, which is reproduced as Table 1 below (a sustained interruption is defined elsewhere in the SCONRRR report as one that lasts longer than one minute).

Table 1 **SCONRRR Table 2 - Reliability data sets – sustained interruptions**

Title	Data set
Overall interruptions	All sustained interruptions including transmission, directed load shedding, planned and unplanned
Distribution network interruptions – planned and unplanned	Excludes: • transmission outages • directed load shedding
Normalised distribution network (interruptions) – unplanned	Further excludes outages which: • exceed a threshold SAIDI impact of three minutes • are caused by exceptional natural or third party events • the (network provider) cannot reasonably be expected to mitigate of the event on interruptions by prudent asset management (sic)

Notes:

1 Distribution network interruptions are disaggregated into planned and unplanned interruptions. Planned interruptions are interruptions for which the required notice has or should have been given.

2 Normalised distribution network interruptions are calculated by subtracting allowable excluded outages from distribution network unplanned interruptions

3 Details of all events which result in excluded outage, including the overall SAIDI impact (distribution unplanned), are to be individually reported.

Source: SCONRRR 2002

The Commission's proposed approach has fewer 'levels' of reporting than the standard SCONRRR reporting. However, the Commission's approach appears to be consistent with the SCONRRR approach as far as the smaller set of categories is concerned. Both the Commission's approach and SCONRRR's begin with all interruptions lasting longer than one minute.[22] They then 'adjust' this total based on certain definitions. The definitions themselves are different.

Table 2 shows how the two definitions 'map' to one another.

22 With the move towards Smart Grids there have been suggestions that this should be changed to a longer period, such as three or five minutes.

Table 2 **Utilities Commission and SCONRRR - excluded outages**

Utilities Commission definition	SCONRRR definition	Comment
Load shedding	Load shedding	Consistent
System controller	Cannot reasonably be avoided by network provider	Consistent
Police or other authorised officer	Cannot reasonably be avoided by network provider	Consistent
Traffic accident	Third party event	Consistency subject to interpretation
Vandalism	Third party event	Consistency subject to interpretation [a]
Natural event identified under 2.5 beta method	Exceptional natural event and event that exceeds SAIDI threshold of three minutes	Consistent because events that exceed the SAIDI threshold of three minutes, or are exceptional natural events, are likely to be 2.5 beta events [b, c]
Customer caused interruption	Third party event	Subject to interpretation
Transmission and distribution events are separated by clauses 1.4.1(a) and 1.7.4(a) of schedule 2 of the draft Code	Transmission outage	Consistent

[a] Traffic accidents and vandalism are assumed not to be considered 'exceptional third party events' within the SCONRRR definition.

[b] the IEEE 2.5 beta method is not expressly referred to in SCONRRR's definition, but we understand that its use has become standard practice.

[c] this is the definition used for the Service Target Performance Incentive Scheme, rather than performance reporting

As Table 2 shows, the Commission's proposed approach is generally consistent with the SCONRRR approach, though there is room for inconsistency between the SCONRRR definition of excluded events and that proposed by the Commission due to possible different interpretations of 'third party event' clause in the SCONRRR definition.

It is possible that these definitions could be interpreted consistently with one another, for example by treating outages due to vandalism as outages which the network service provider could "not reasonably be expected to [prevent]… by prudent asset management." However, this is subject to the Commission's interpretation.

We note that PWC has submitted to the Commission that its proposed application of the two approaches is contrary to industry practice. In PWC's submission, industry practice goes no further than adjusting actual outages for extreme events using the IEEE 1366 '2.5 beta method'. As Table 2 shows, this is not entirely correct, though it is closer to, for example, the service standards applied by the Essential Services Commission of South Australia.[23]

23 In summary, ESCOSA determined to continue with its 'no exclusions' approach. For details see ESCOSA, "ETSA Utilities Service Standards Framework" Issues paper and Final decision, both available from www.escosa.sa.gov.au.

Therefore, while the Commission's proposed set of exclusions may not be entirely consistent with accepted industry practice, that practice does not limit adjustments only to the 2.5 beta method.

5 Generation sector performance indicators

The performance indicators the Commission proposes to apply to the generation sector are:

1. Availability Factor (AF)
2. Unplanned Availability Factor (UAF)
3. Equivalent Availability Factor (EAF)
4. Forced Outage Factor (FOF)
5. Equivalent Forced Outage Factor (EFOF)
6. SAIDI
7. SAIFI

SAIDI and SAIFI are discussed in chapter 3 of this report. The others are discussed in this chapter.

Four of the five performance indicators discussed in this chapter are paired with one another because they are calculated the same way based on different data. Therefore:

- section 5.1 relates to AF[24]
- section 5.2 relates to UAF and FOF
- section 5.3 relates to EAF and EFOF

These three sections address the first of the Commission's questions, namely the consistency of the generation performance indicators as between the consultation paper and the draft Code.

As discussed in section 2 above, the electricity generation sector is not generally required to publish performance related material. Therefore, there is no clearly defined 'accepted industry practice' for reporting performance. For this reason, the focus of our review of performance indicators for the generation sector indicators is on the consistency in the definitions in the consultation paper and the draft Code.

Section 5.4 provides a discussion of generally accepted industry practice.

[24] Planned forced outages cannot exist by definition, so there is not forced outage measure to correspond with AF

5.1 Availability Factor

The Commission's intention as set out in the consultation paper is that AF should measure how often a generating unit is available for operation. AF takes account of 'down times' due to both planned and unplanned outages. Mathematically, it is described in the consultation paper as equation (4).

$$AF = 1 - \left(\frac{Sum(Unavailable\ hours_{unit\ i} \times NMC_{unit\ i})}{Sum(Hours_{unit\ i} \times NMC_{unit\ i})}\right) \tag{4}$$

where:

Unavailable hours is the number of hours for which the generating unit in question experienced an outage, whether planned or unplanned, during the reporting period.

NMC is Net Maximum Capacity, calculated in accordance with IEEE standard 762-2006

Hours is the number of hours in the reporting period for which the generating unit had been commissioned, usually all hours in the reporting period

In the draft Code, AF is defined using equation (5):

$$AF = 1 - \left(\frac{\sum_{i=1}^{n}(UH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right) \times 100 \tag{5}$$

where:

UH is the total number of ***hours*** that a ***generating unit*** is unavailable due to ***planned outages*** and ***unplanned outages***. This excludes the number of ***equivalent partial outage hours*** due to ***partial planned outages*** and ***partial unplanned outages.***

NMC is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)[25]

H is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period.***

The AF is expressed as a percentage

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25 There appears to be a formatting error in this section of the draft Code. Specifically, the defined terms in the definition of NMC are in bold, but not italic, font.

We have identified two issues with the Commission's proposed definition of AF. The first is an error in the formula in the code. This arises from the only change between the formulae in the consultation paper and the draft Code.

The change was to multiply AF by 100 so that it ranges from 1 to 100 and can be read easily as a percentage. In doing this, though, a bracket should have been added so that the formula reads as per equation (6):

$$AF = \left(1 - \left(\frac{\sum_{i=1}^{n}(UH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right)\right) \times 100 \qquad (6)$$

where terms are as per equation (5)

Alternatively, AF could be read as a percentage ranging from 0 to 1.

This bracket was used in the calculated example shown in the code, so we take the omission as a typographical error.

The second issue relates to the choice of NMC as the measure of the size of a generating unit. This applies to all of the performance indicators discussed in this chapter and is discussed in section 5.4.

5.2 Unplanned Availability Factor and Forced Outage Factor

UAF is related to AF. The difference between the two is that UAF applies only to outages that were not planned in advance and notified to the System Controller. [26]

[26] There appears to be a typographical error in paragraph 3.74 of the consultation paper, which suggests that UAF should be calculated after removing "unplanned outages". We have assumed that this was intended to mean that "planned outages" should be removed.

Mathematically, UAF is described in the consultation paper as equation (7).

$$UAF = 1 - \left(\frac{Sum(UOH_{unit\ i} \times NMC_{unit\ i})}{Sum(Hours_{unit\ i} \times NMC_{unit\ i})} \right) \qquad (7)$$

where:

UOH is the number of hours for which the generating unit in question experienced an unplanned outage during the reporting period.[27]

NMC is Net Maximum Capacity, calculated in accordance with IEEE standard 762-2006

Hours is the number of hours in the reporting period for which the generating unit had been commissioned, usually all hours in the reporting period

In the draft Code, UAF is defined using equation (8):

$$UAF = 1 - \left(\frac{\sum_{i=1}^{n}(UOH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)} \right) \times 100 \qquad (8)$$

where:

UOH is the total number of ***hours*** that a ***generating unit*** is unavailable due to ***unplanned outages***.

NMC is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

H is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period.***

The UAF is expressed as a percentage.

UAF is closely related to FOF. Both are calculated the same way, and both are expressed in similar terms in the consultation paper and the draft Code. The difference between the two is simply that FOF applies to a smaller subset of outages. A forced outage is, essentially, an unplanned outage that could not be delayed until a period of reduced demand. In simple terms, a forced outage is an urgent unplanned outage.

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[27] UOH was spelled out in full as Unplanned Outage Hours in the consultation paper. It is abbreviated here for ease of presentation.

Mathematically, FOF is described in the consultation paper as equation (9).

$$FOF = \left(\frac{Sum(FOH_{unit\ i} \times NMC_{unit\ i})}{Sum(Hours_{unit\ i} \times NMC_{unit\ i})}\right) \tag{9}$$

where:

FOH is the number of hours for which the generating unit in question experienced a forced outage during the reporting period.[28]

NMC is Net Maximum Capacity, calculated in accordance with IEEE standard 762-2006

Hours is the number of hours in the reporting period for which the generating unit had been commissioned, usually all hours in the reporting period

In the draft Code, FOF is defined using equation (10):

$$FOF = \left(\frac{\sum_{i=1}^{n}(FOH \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right) \times 100 \tag{10}$$

where:

FOH is the total number of ***hours*** that a ***generating unit*** is unavailable due to ***forced outages***. This excludes the number of ***equivalent partial outages*** [29] ***hours*** due to ***partial unplanned outages.***

NMC is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

H is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period.***

FOF is expressed as a percentage.

The definition of UOH in the UAF formula does not exclude partial unplanned outages explicitly. This introduces the risk that UAF and EAF will be confused with one another.

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28 FOH was spelled out in full as Forced Outage Hours in the consultation paper. It is abbreviated here for ease of presentation.

29 There is a typographical error here, this should read “outage”.

The FOF equation in the draft code contains an undefined variable 'x'. It is apparent from the worked example in the draft code that this was intended to be a multiplication symbol. We have assumed that this was simply a typographical error.

Aside from this, the definitions of UAF and FOF in the draft code correspond with their descriptions in the consultation paper. The only difference between the two definitions of UAF and FOF is that, in the draft code, both are multiplied by 100 to allow them to be read easily as a percentage.

Similarly to the formula for AF, the formula for UAF in the draft code is missing a set of brackets. If the formula is to reflect the worked example and the Commission's intended result, it should be re-written as shown in equation (11):

$$UAF = \left(1 - \left(\frac{\sum_{i=1}^{n}(UOH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right)\right) \times 100 \qquad (11)$$

where terms are as defined in equation (8).

5.3 Equivalent Availability Factor and Equivalent Forced Outage Factor

The preceding three generator performance indicators, AF, UAF and FOF only 'count' incidents when a generating unit is unavailable in its entirety. However, it is also possible for a unit to be partially unavailable, or 'derated'.

The next two proposed performance indicators, EAF and EFOF, build on UAF and FOF by taking account of these partial outages.

As with UAF and FOF, these two performance indicators are conceptually similar, but calculated using different data to reflect the difference between unplanned and forced outages.

EAF is described in the consultation paper as equation (12).

$$EAF = 1 - \left(\frac{Sum(UH_{unit\ i} \times NMC_{unit\ i}) + Sum(PAH_{unit\ i} \times NMC_{unit\ i})}{Sum(Hours_{unit\ i} \times NMC_{unit\ i})}\right) \tag{12}$$

where:

UH is the number of hours for which the generating unit in question experienced an outage, whether planned or unplanned, during the reporting period.

NMC is Net Maximum Capacity, calculated in accordance with IEEE standard 762-2006

PAH is not defined in the consultation paper.[30,31]

Hours is the number of hours in the reporting period for which the generating unit had been commissioned, usually all hours in the reporting period

30 PAH was spelled out in full as Partial Availability Hours in the consultation paper. It is abbreviated here for ease of presentation.

31 PAH was taken to mean the number of hours for which a generating unit was *only* partially available, not the number of hours for which it was *at least* partially available. It would have been clearer, and more consistent with the rest of the paper, to have referred to Partial *Un*availability Hours. This change was made in the draft Code, which is expressed in terms of partial outages.

In the draft Code, EAF is defined using equation (13):[32]

$$EAF = \left(1 - \left(\frac{\sum_{i=1}^{n}(UH_i \times NMC_i) + \sum_{i=1}^{n}(EH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right)\right) \times 100 \qquad (13)$$

where:

UH is the total number of ***hours*** that a ***generating unit*** is unavailable due to ***planned outages*** and ***unplanned outages***.

NMC is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

EH is the total ***equivalent partial outage hours*** due to ***planned partial outages*** and ***partial unplanned outages***.

H is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period.***

The EAF is expressed as a percentage.

32 The formula in the draft Code lacks the large bracket and the second summation in the numerator. Without these the formula would not perform as described so we have assumed that these were typographical errors.

EFOF is described in the consultation paper as equation (14).

$$EFOF = \left(\frac{Sum(FOH_{unit\ i} \times NMC_{unit\ i}) + Sum(PFOH_{unit\ i} \times NMC_{unit\ i})}{Sum(Hours_{unit\ i} \times NMC_{unit\ i})}\right) \qquad (14)$$

where:

FOH is the number of hours for which the generating unit in question experienced a forced outage during the reporting period.

NMC is Net Maximum Capacity, calculated in accordance with IEEE standard 762-2006

PFOH is not defined in the consultation paper.[33]

Hours is the number of hours in the reporting period for which the generating unit had been commissioned, usually all hours in the reporting period

33 PFOH was spelled out in full as Partial Forced Outage Hours in the consultation paper. It is abbreviated here for ease of presentation.

In the draft Code, EFOF is defined using equation (15):[34]

$$EFOF = \left(\frac{\sum_{i=1}^{n}(FOH_i \times NMC_i) + \sum_{i=1}^{n}(EH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right) \times 100 \qquad (15)$$

where:

FOH is the total number of ***hours*** that a ***generating unit*** is unavailable due to ***forced outages***.

NMC is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

EH is the total ***equivalent partial outage hours*** due to ***partial forced outages***.

H is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period.***

EFOF is expressed as a percentage.

The definitions of EAF and EFOF in the draft code and consultation paper are consistent with one another. However, we identified three issues that the Commission may wish to address.

The first issue is that the formulae for both EAF and EFOF contain the term EH, although it has a different meaning in each case.

In the EAF formula, EH, refers to partial *unplanned* outages, while in the EFOF formula it refers to partial *forced* outages.

The definition of terms that follows the two formulae makes the different definitions clear, but, in our view, it is confusing to use the same term to mean different things in the draft Code. This gives rise to the possibility that the same value could be used incorrectly in both calculations.

The Commission may wish to modify the terms in the draft Code, for example it may choose to use EUH (for Equivalent Unavailability Hours) in the EAF formula and EFOH (for Equivalent Forced Outage Hours) in the EFOF formula.

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[34] The formula in the draft Code lacks the second summation in the numerator. Without this, or another pair of brackets, the formula would not perform as described so we have assumed that this was a typographical error.

The second issue relates to the definition of EH in the draft code following the EAF formula (clause 1.4.7). That definition refers to planned partial outages, whereas schedule 4 of the draft Code, which contains the definitions, refers to partial planned outages.

The third issue is that, as with the definition of UH in the EAF formula, the definition of FOH in the EFOF formula does not exclude partial outages explicitly. This introduces the risk that these outages will be double counted given that they are also accounted for by the term EH.

5.4 Using NMC as the measure of generating unit size

The various generator performance indicators the Commission proposes to use are all measures of the proportion of a generating unit' total *potential* capacity that was *actually* available to the market in the reporting period. Computing this requires a measure of the generating unit's total potential capacity.

The Commission has proposed to use Net Maximum Capacity (NMC) as the measure of total potential capacity. This is the generating unit's maximum capacity *after* accounting for auxiliary loads.

PWC has submitted that it would be more appropriate to use Gross Maximum Capacity (GMC) for this purpose because the auxiliary load varies significantly with the ambient conditions and load, making NMC variable and more difficult to report.

It is not within the scope of this review to comment on whether NMC or GMC would be the most appropriate measure other than by considering which, if either, is more widely used in the industry. However, as discussed in section 2, the generation sector of the electricity industry in Australia is typically not subject to performance reporting, at least not in the public domain. Therefore, this provides little or no assistance.

AEMO compiles statistics, though these are not published, relating to the availability of certain plant in the NEM. These are an input to AEMO's Projected Assessment of System Adequacy.

For this purpose, AEMO's forced outage reporting guideline requires the use of 'winter capacity', which is GMC in winter time. To the extent that this indicates accepted industry practice, this suggests that the Commission may wish to consider adopting PWC's preferred approach.

In considering this, the Commission may also wish to consider the magnitude of the difference between NMC and GMC. The level of precision embedded in this choice may be unnecessary given that what is being sought is essentially a measure of how often generators are 'broken down for' the difference is probably not that large.

The final factor the Commission may wish to consider is the need for comparison over time within the Territory. This would provide an argument in support of maintaining the status quo.

6 Transmission sector performance indicators

The performance indicators the Commission proposes to apply to the transmission sector are:

1. Average Circuit Outage Duration (ACOD) (Unadjusted and Adjusted)
2. Frequency of Transmission Circuit Outages (FCO) (Unadjusted and Adjusted)
3. Average Transformer Outage Duration (ATOD) (Unadjusted and Adjusted)
4. Frequency of Transformer Outages (FTO) (Unadjusted and Adjusted)
5. SAIDI (Unadjusted and Adjusted)
6. SAIFI (Unadjusted and Adjusted)

SAIDI and SAIFI are discussed in chapter 3 of this report. The others are discussed in this chapter.

The performance indicators discussed in this chapter are paired with one another because two are average durations and two are frequencies. Within these pairs they are calculated the same way using different data. Therefore:

- section 6.1 relates to the two average durations, ACOD and ATOD
- section 6.2 relates to the two frequencies, FCO and FTO

All of these indicators are proposed to be applied on both an adjusted and unadjusted basis, using the adjusted data set discussed in chapter 4. Issues associated with this approach are discussed in that chapter.

The indicators discussed in this chapter would apply only to the transmission network in the Territory as defined in the draft Code. In simple terms, they relate to the high voltage network that transfers electricity from generators to distribution networks, though some customers may also be connected to the transmission network.

6.1 Average outage duration – circuit and transformer

ACOD measures the average length of transmission network outages.

In the consultation paper it is defined using equation (16):[35]

$$ACOD = \left(\frac{Sum(Transmission\ Circuit\ Outage\ Minutes_i)}{Sum(Transmission\ Outage_i)}\right) \quad (16)$$

In the draft Code ACOD is defined as equation (17):[36]

$$ACOD = \left(\frac{\sum_{i=1}^{n} COD_i}{\sum_{i=1}^{n} CI_i)}\right) \quad (17)$$

where:

∑COD	is the sum of the duration for all ***network outages*** expressed in minutes
∑CI	is the sum of ***network outages***
i	is not defined in the draft Code

[35] In the consultation paper the numerator referred to "…unplanned outage minutes'. The Commission advised that the word 'unplanned' was included in error so we have disregarded it. We note that the text of the consultation paper was clear that ACOD was intended to be calculated based on "all network outages".

[36] The draft Code definition of adjusted ACOD includes "NOI" in the definitions below the equation. We have assumed that this is a typographical error and that it should read ∑CI

ATOD measures the average length of a subset of transmission outages, being those caused by transformer issues. It is defined in the consultation paper and the draft Code using equations (18) and (19) respectively.[37]

$$ATOD = \left(\frac{Sum(Transmission\ Transformer\ Outage\ Minutes_i)}{Sum(Transmission\ Outage_i)}\right) \tag{18}$$

$$ATOD = \left(\frac{\sum_{i=1}^{n} TOD_i}{\sum_{i=1}^{n} CI_i)}\right) \tag{19}$$

where:

∑TOD	is the sum of the duration for all ***network outages*** expressed in minutes
∑TI	is the sum of ***network outages***
i	is not defined in the draft Code

The calculation that is used to calculate the average outage duration, whether 'circuit' or 'transformer' and whether 'adjusted' or not is simply the total length of outages (in minutes) on the network divided by the number of outages.

In our view, the denominator of the ACOD and ATOD formulae are unnecessarily complex. It would be sufficient to divide the numerator by the same number '*n*' as used in the summation operator in the numerator. That is, Average outage duration could be expressed simply as equation (20):

$$AOD = \left(\frac{\sum_{i=1}^{n} OD_i}{n}\right) \tag{20}$$

where, for all ***network outages*** *i*:

OD	is the total duration of ***network outages***, either circuit or transformer and either adjusted or unadjusted
n	is the number of ***network outages*** experienced during the reporting period

[37] In the consultation paper the numerator referred to "…unplanned outage minutes'. The Commission advised that the word 'unplanned' was included in error so we have disregarded it. We note that the text of the consultation paper was clear that ATOD was intended to be calculated based on "all network outages".

In addition, the draft code formulae for ACOD and ATOD, adjusted and unadjusted, include an unnecessary bracket in the denominator.

6.2 Frequency of outages – Circuit and Transformer

FCO and FTO are referred to as the frequency of circuit and transformer outages respectively. However, when the reporting period is constant these become counts rather than true frequencies.[38]

They are expressed in the consultation paper and the draft code in similar terms as shown in equation (21):

$$FO = \sum_{i=1}^{n} I_i \tag{21}$$

Where:

FO is the Frequency of either circuit or transformer outages, either adjusted or unadjusted

∑I is the sum of ***network outages*** *i*

A frequency is a measure of the rate at which a particular event occurs. It is calculated by dividing the number of times that event was observed either by the number of times it could have occurred or by a period of time. For example SAIFI is the number of customers who experienced an interruption divided by the number of customers who could have experienced an interruption.

FCO and FTO are simply the number of outages of a particular type that occur in a given reporting period. If the reporting period is constant, for example one year, there is no additional value in presenting them as frequencies. In the formulae shown above it would be sufficient simply to use the value '*n*', which is consistent with the formula set out in the ACCC's statement of principles.

[38] Clause 4 of the draft Code sets out the requirement that reporting is conducted once each financial year.

7 Distribution sector performance indicators

The performance indicators the Commission proposes to apply to the transmission sector are:

1. SAIDI (Unadjusted and Adjusted)
2. SAIFI (Unadjusted and Adjusted)
3. Feeder performance indicators

SAIDI and SAIFI are discussed in chapter 3 of this report. Feeder performance is discussed in this chapter.

7.1 Feeder performance

It is common to hear electricity distribution networks described as if they are a single, homogeneous unit. Performance is often reported and compared at the network level, as if all customers connected to the network receive the same level of service.

In practice, though, networks are not homogeneous. The performance of an electricity distribution network will vary feeder by feeder depending on local conditions, whether the feeder is part of a meshed or radial network, the length of the feeder and other factors.

In some cases, individual feeders will perform significantly less well than the average. The Commission proposes to measure the performance of these feeders individually using the ratio of the individual feeders SAIDI performance to the SAIDI performance target for feeders of its category.

The feeder performance ratio was described in the consultation paper and the draft code in the same way, using equation (22):

$$SPR = \frac{SAIDI\ of\ individual\ feeder}{SAIDI\ target\ standard\ for\ feeder\ category} \tag{22}$$

The Commission has not yet determined the SAIDI target standards. When this is determined, and SAIDI performance for each feeder is reported, it will be possible to determine the feeder performance ratio for each feeder. Feeders which perform worse (i.e. have a higher ratio) than an as yet undetermined threshold will be subject to increased monitoring.

The description of the feeder performance measure is consistent as between the consultation paper and the draft Code.

8 Conclusion and recommendation

This section provides a summary of the steps we recommend be taken to address the issues identified in this review.

8.1 Recommendations – General

The draft Code refers, in the definition of "IEEE 2.5 beta method" to IEEE Standard 1366 (2003). Clause 1.6.1 refers to the 2001 version of the same standard. That standard was updated in May 2012. The draft Code should be amended to refer to the 2012 version of the standard.

The formulae in the draft code do not specify the meaning of the index number '*i*'. In formulae containing '*i*' the draft code should be amended to insert, after "where" words to the following effect "for all (interruptions, generating units, etc.) *i*". However, in many cases the formulae can be simplified to avoid using summation operators and the subscript '*i*'. Where this is possible, we recommend that it be done. Section 8.8 contains a consolidated list of the formulae for that we recommend the Commission uses for all performance indicators.

8.2 Recommendation - SAIDI

The definition of SAIDI for the generation sector should be altered to exclude momentary generation outages if this is the Commission's intention.

A preferable expression of SAIDI that addresses the problems identified with the current expression, would be to use equation (23).The definitions will need to be slightly different the different sectors and to account for adjusted and unadjusted SAIDI.

8.3 Recommendation – SAIFI

The definition of SAIDI for the generation sector should be altered to exclude momentary generation outages if this is the Commission's intention.

SAIFI is a simpler calculation than SAIDI and the subscript "*i*" is unnecessary. It is sufficient to define SAIFI as shown in equation (24).

The definitions will need to be slightly different the different sectors and to account for adjusted and unadjusted SAIFI.

8.4 Recommendation – AF

A set of brackets should be added to the AF formula in the draft code so that it reads as per equation (25):

Alternatively, AF could be read as a percentage ranging from 0 to 1.

8.5 Recommendation UAF and FOF

The definition of UOH in the UAF formula should be amended to exclude partial unplanned outages explicitly.

The FOF equation in the draft code contains an undefined variable '*x*'. The draft Code should be amended to replace it with a multiplication sign.

Similarly to the formula for AF, the formula for UAF in the draft code is missing a set of brackets. If the formulae are to reflect the worked example and the Commission's intended results, they should be re-written as shown in equations (26) and (28).

8.6 Recommendation EAF and EFOF

The definition of UOH in the EAF formula does not exclude partial unplanned outages explicitly.

The same issue affects the definition of FOH in the EFOF formula.

The term EH is used for different meanings in EAF and EFOF formulae in the draft Code. The draft Code should be amended to use EUH and EFOH instead of EH.

The definition of EH in the EAF formula refers to "planned partial outages", which is not defined in the draft Code. This should be amended to read "partial planned outages".

8.7 Recommendations, ACOD, ATOD, FCO, FTO

The denominators of ACOD and ATOD and the formulae for FCO and FTO are unnecessarily complex. The draft Code should be amended to replace all with the total number of interruptions of the appropriate type for each formula.

8.8 Consolidated list of formulae

8.8.1 SAIDI

$$SAIDI = \frac{CMI}{CS} \tag{23}$$

where, for all ***interruptions*** (or ***generation outages***):

CMI is customer minutes of interruption, calculated as the sum of the duration of each ***customer interruption*** (in minutes) during the ***reporting period***

CS is the average of the number of ***customers*** supplied at the beginning of the ***reporting period*** and the number of customers supplied at the end of the ***reporting period*** (by the relevant network)

8.8.2 SAIFI

$$SAIFI = \frac{CI}{CS} \tag{24}$$

Where:

CI is the total number of ***customers*** that experienced an ***interruption*** (or ***generation outage***) during the reporting period

CS is the average of the number of ***customers*** supplied at the beginning of the ***reporting period*** and the number of ***customers*** supplied at the end of the ***reporting period*** (by the relevant network)

8.8.3 AF

$$AF = \left(1 - \left(\frac{\sum_{i=1}^{n}(UH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right)\right) \times 100 \qquad (25)$$

Where, for each ***generating unit*** *i*:

UH — or unavailable hours is the total number of ***hours*** that a ***generating unit*** was unavailable during the ***reporting period*** due to ***planned outages*** or ***unplanned outages***. This excludes the number of ***equivalent partial outage hours*** due to ***partial planned outages*** and ***partial unplanned outages***

NMC — is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)[39]

H — is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period***

AF is expressed as a percentage

8.8.4 UAF

$$UAF = \left(1 - \left(\frac{\sum_{i=1}^{n}(UOH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right)\right) \times 100 \qquad (26)$$

Where, for each ***generating unit*** *i*:

UOH — or unplanned outage hours is the total number of ***hours*** that a ***generating unit*** was unavailable during the ***reporting period*** due to ***unplanned outages.*** This excludes the number of ***equivalent partial outage hours*** due to ***partial unplanned outages***

NMC — is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

H — is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period***

[39] There appears to be a formatting error in this section of the draft Code. Specifically, the defined terms in the definition of NMC are in bold, but not italic, font.

UAF is expressed as a percentage

8.8.5 EAF

$$EAF = \left(1 - \left(\frac{\sum_{i=1}^{n}\left((UH_i + EUH_i) \times NMC_i\right)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right)\right) \times 100 \qquad (27)$$

Where, for all ***generating units*** *i*:

UH — or unavailable hours is the total number of ***hours*** that a ***generating unit*** was unavailable during the ***reporting period*** due to ***planned outages*** or ***unplanned outages***. This excludes the number of ***equivalent partial outage hours*** due to ***partial planned outages*** and ***partial unplanned outages***

EUH — equivalent unavailable hours is the total ***equivalent partial outage hours*** due to ***partial planned outages*** and ***partial unplanned outages*** during the ***reporting period***.

NMC — is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

H — is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period***

EAF is expressed as a percentage

8.8.6 FOF

$$FOF = \left(\frac{\sum_{i=1}^{n}(FOH_i \times NMC_i)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right) \times 100 \quad (28)$$

Where, for each ***generating unit*** *i*:

FOH — or forced outage hours is the total number of ***hours*** that a ***generating unit*** was unavailable during the ***reporting period*** due to ***forced outages***. This excludes the number of ***equivalent partial outage hours*** due to ***partial forced outages***

NMC — is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

H — is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period.***

FOF is expressed as a percentage.

8.8.7 EFOF

$$EFOF = \left(\frac{\sum_{i=1}^{n}\left((FOH_i + EFOH_i) \times NMC_i\right)}{\sum_{i=1}^{n}(H_i \times NMC_i)}\right) \times 100 \qquad (29)$$

Where, for all ***generating units*** *i*:

FOH of forced outage hours is the total number of ***hours*** that a ***generating unit*** was unavailable during the ***reporting period*** due to ***forced outages***. This excludes the number of ***equivalent partial outage hours*** due to ***partial forced outages***

EFOH or equivalent forced outage hours is the total ***equivalent partial outage hours*** due to ***partial forced outages*** during the ***reporting period***

NMC is the ***net maximum capacity*** (applicable to weighted multiple ***generating units*** that are part of the same ***power station***)

H is the total number of ***hours***. However, if a ***generating unit*** is commissioned during the relevant ***reporting period***, H will be the total number of ***hours*** from the data the ***generating unit*** is commissioned up until the end of that ***reporting period***

EFOF is expressed as a percentage

8.8.8 ACOD

$$ACOD = \left(\frac{COD}{NO}\right) \qquad (30)$$

Where, for each ***transmission network***:

COD is the total duration of ***network outages*** experienced during the ***reporting period***

NO is the number of ***network outages*** experienced during the ***reporting period***

8.8.9 FCO

$$FCO = NO \qquad (31)$$

Where, for each ***transmission network***:

NO is the number of ***network outages*** experienced during the ***reporting period***

8.8.10 ATOD

$$ATOD = \left(\frac{TOD}{TO}\right) \tag{32}$$

Where, for each ***transmission network***:

TOD is the total duration of ***network outages*** caused by ***transformer related events*** during the ***reporting period***

TO is the number of ***network outages*** caused by ***transformer related events*** during the ***reporting period***

8.8.11 FTO

$$FTO = TO \tag{33}$$

Where, for each ***transmission network***:

TO is the number of ***network outages*** caused by ***transformer related events*** during the ***reporting period***

8.8.12 SAIDI performance ratio

$$SPR_{ij} = \frac{SAIDI_i}{SAIDI\ target_j} \tag{34}$$

Where, for all ***feeders*** *i* of ***feeder category*** *j:*

SAIDI is the System Average Interruption Duration Index

SAIDI target is the SAIDI performance target for feeders of the relevant ***feeder category***