Western Australia Electricity Market

Metrology Procedure for Metering Installations

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About this document

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Document version history

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V2 Draft	26 Apr 06		Updated document template/styles and restructured to be closer match to new draft NEM Metrology Procedures
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V4 Issue	22 May 06		Issued to retailers for comment.
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Review and approval

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Contents

1 General

1.1 Introduction

1.1.1 The title of this document is the "*Western Australian Electricity Market Metrology Procedure for Metering installations*".

1.1.2 The short title of this document is the "*WA Metrology Procedure*".

1.1.3 The *WA Metrology Procedure* is made in accordance with clauses 6.2 and 6.8 of the *Metering Code*.

1.2 Purpose

1.2.1 The purpose of this *Metrology Procedure* is:

a) to provide guidance to the *responsible person* on the correct provision, installation and maintenance of *metering installations* in line with the principles of the *Metering Code*; and

b) to provide guidance to interested third parties, such as metering manufacturers, on the requirements for metering within the Western Australian electricity system.

1.3 Scope

1.3.1 The *Metrology Procedure* provides information on the application of *metering installations* at *connection points*. In particular this *Metrology Procedure* sets out provisions for *metering installations* relating to:

a) the devices and methods that are used by the *Network Operator* to:

i) measure, or determine by means other than a device, electricity produced and consumed at a metering *point*, and

ii) convey the measured or determined information to other devices using *communications links*, and

iii) prepare the information using devices or methods to form *energy data*; and

iv) provide access to the *energy data* from a telecommunications network; and

b) specify the minimum requirements for *meter*s and *metering installation*s, including:

i) *accumulation meters*; and

ii) interfaces that allow *interval energy data* to be downloaded; and

iii) direct connected *meters* for Type 4 to Type 6 *metering installations*; and

iv) *CT*s and *VT*s; and

v) programmable settings under clause 3.10 of the *Metering Code*.

c) specify the procedures for estimating, substituting and validating energy data under the *Metering Code*; and

d) be consistent with the approved asset management system required by section 14 of the Act; and

e) define the rights of access to *energy data* in the *metering installation* and

f) Define the procedures for the auditing of *metering installations.*

1.3.2 The *Metrology Procedure* applies to the *Code Participant* and the *Network Operator* in relation to a *load* at a *connection point*.

1.3.3 The *Metrology Procedure* sets out those obligations and duties that are imposed on the *Network Operator* with regards to *meter* and *energy data* provision by the *Metering Code* and *Market Rules*.

1.3.4 The *Metrology Procedure* covers the full extent of a *metering installation*, from the *connection point* at one extreme to the boundary of the *telecommunications network* at the other extreme. It includes connection of the *metering installation* to the *telecommunications network*.

{Explanation:

The *connection point* is a logical construction indicating a point of entry or exit to the electricity network and is assigned a unique *NMI*. The *connection point* may be associated with one or more physical *attachment points* providing each *attachment point* operates at the same voltage. Similarly, a single *attachment point* may be associated with multiple *connection points*.

A metering *point* is the point on the *network* at which an *energy data* measurement is taken by a *revenue meter,* or, for type 7 *meter*s, is the point at which a calculated *energy data* figure is deemed to have been measured. Each *connection point* may be associated with multiple metering *points*.

A *metering installation* is designed for each metering *point* for the purpose of measuring energy to a fiscal standard. Each *metering installation* of type 1-6 contains a single *revenue meter* and may also contain a *check meter,* which may be physically distinct from the *revenue meter*. For example, the *metering installation* may physically consist of separate equipment housings each containing separate elements of the *metering installation*. In this case the metering *point* is co-located with the *revenue meter* and the *check meter* would be deemed to measure energy at the same metering *point*. In such circumstances, the design of the *metering installation* would take into account any corrections necessary because of the physical separation of the check and revenue *meter*s and these would be recorded as correction factors.

For example, consider a domestic connection. In a typical house the *attachment point* would usually be a green power dome and the metering *point* would usually be the *meter* box on the side of the house. The *connection point* is the logical point that electricity leaves the network and enters the residence. For practical purposes in this example the *attachment point* and *connection point* are synonymous. However, if the property consisted of an older building that had been subdivided into two separate residences, the situation might be a little different. In this case there might still be a single *attachment point*. However, each residence would be deemed to have its own supply and hence its own *connection point* and NMI. Each residence would have a separate *meter* box (housing the *metering installation* and hence metering *point*) and associated *revenue meter.*

Another example might be a factory that has multiple *attachment points*. The retailer and factory owner may wish to have their aggregate consumption recorded as a single figure. Under these circumstances, providing the *attachment points* operate at the same voltage and the *meter*s are all either accumulation or interval *meter*s but not a combination of both, the retailer may apply to have the multiple *attachment points* treated as a single *connection point* with multiple metering *points*, each with its associated *metering installation*.

Meters in this *Metrology Procedure* are divided into two classes: *revenue meters* and *check meters*. *Revenue meters* are used for fiscal purposes and will meet the accuracy requirements specified below for each *meter* type 1 to 6 as appropriate. *Check meters* are used to validate the correct functioning of the *revenue meter* and may be used to generate *substitute* data if there is a problem with the *revenue meter*. *Check meters* may be of lower precision (up to twice the uncertainty) than the associated *revenue meter* and may be located at a different physical location but will measure *energy data* for the same metering *point*.

A *metering installation* has an end-to-end path that consists of:

- One or more devices to measure the flow of electricity in a power conductor (including a *current transformer* and *voltage transformer* where appropriate, and a *measurement element* usually in the form of a *meter*) and in doing so produces *energy data*; and

- For types 1 to 5 and, optionally, for type 6, a *data logger*, which is a device to record and store (for a limited period) the *energy data* produced by the measurement element in the form of 30-minute energy packets or energy packets in sub-multiples of 30 minutes; and

- A *communications link*, which has the role of connecting the *data logger* to the *telecommunications network*, and in doing so allows *energy data* to be extracted (pushed or pulled) from the *metering installation*.

For a type 1, type 2, type 3 and type 4 *metering installation*, the boundary of the *telecommunications network* is usually at the site of the power conductor, and physically close to the *data logger*. The *data logger* may be within the housing of the measuring element, or a separate device to the measuring element device. That is, a *meter* may contain only a measuring element, or a combined *measuring element* and *data logger*. In either case, for a type 1, type 2, type 3 and type 4 *metering installation*, the *communication link* might consist of only a modem and isolation links for a PSTN connection, or a combined mobile phone and modem for a CDMA, GSM, GPRS or 3G connection. Once connection to the telecommunications network has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *data logger* on a regular cycle. Note that an option exists for the type 1, type 2, type 3 and type 4 *metering installation*s to extend the *communications link* so that the connection to the *telecommunication network* is made at a location remote from the site of the power conductor. However, the 'extended' *communications link* would need to be a seamless electronic process that permitted the *Network Operator* to obtain *energy data* from the *metering installation* by *remote acquisition*.

For a type 5 *metering installation*, the boundary of the *telecommunications network* would be at a location that is remote to the site of the power conductor, and hence remote from the *data logger*. In this case the *communications link* might consist of:

(a) a manual *meter* read to obtain the *energy data* from the *data logger* (assuming that the *data logger* was within the housing of the *meter*); and,

(b) the manual transfer of the *energy data* from the location of the *meter* to a remote *metering installation database; and*,

(c) the storage of the raw *energy data* within the *metering installation database*; and,

(d) the processing of the *energy data* within the *metering installation database*; and

(e) the storage of the processed *energy data* within that *metering installation database*; and,

(f) the connection of the *metering installation database* to the *telecommunications network*.

Once connection to the *telecommunications network* has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *metering installation database* on a regular cycle.

For a type 6 *metering installation*, the boundary of the *telecommunications network* would be at a location that is remote to the site of the power conductor. For a type 6 there is no *data logger*. In this case the *communications link* might consist of:

(a) a manual *meter* read to obtain the *energy data* from the *meter; and*,

(b) the manual transfer of the *energy data* from the location of the *meter* to a remote *metering installation database; and*,

(c) the storage of the raw *energy data* within the *metering installation database; and*,

(d) the processing of the *energy data* within the *metering installation database; and*,

(e) the storage of the processed *energy data* within that *metering installation database;* and,

(f) the connection of the *metering installation database* to the *telecommunications network*.

Once connection to the *telecommunications network* has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *metering installation database* on a regular cycle. Alternatively, the Metering *Provider* may be required to transfer the energy data to the *Network Operator's* metering *database* where further processing may be undertaken.

For a type 7 *metering installation*, the boundary of the *telecommunications network* would be at a location that is remote to the site of the power conductor. For type 7 there is no *meter* or *data logger*. In this case the *communications link* might consist of:

(a) a *remote metering installation database*; and,

(b) a *load table* and an *inventory table* within the *metering installation database;* and,

(d) the processing of the *energy data* (using the *load* and *inventory table*) within the *metering installation database;* and,

(e) the storage of the processed *energy data* within that *metering installation database*; and,

(f) the connection of the *metering installation database* to the *telecommunications network*.

Once connection to the *telecommunications network* has been made, the *Network Operator* may apply *remote acquisition* techniques to access the *energy data* in the *metering installation database* on a regular cycle. Alternatively, the Metering *Provider* may be required to transfer the energy data to the *Network Operator*'s metering *database* where further processing may be undertaken. }

1.3.5 This *Metrology Procedure* applies to any electricity network for which Western Power is the *Network Operator* or for which Western Power has been appointed metering *data agent*.

1.4 Referenced Material

1.4.1 The document has been produced with reference to the following publications

WP DMS Ref.	Acronym	Document
2728031	"*Metering Code*", "*Code*"	Electricity Industry *Metering Code* 2005, Published in the Western Australian Government Gazette on 23 Dec 2005, No. 243.
2326074	"*Service Level Agreement*", "*SLA*"	Model Service Level Agreement, approved 30 March 2006 version.
2428349	"*Communication Rules*"	*Metering Code* Communication Rules, approved 16 February 2006 version.

1.5 Definitions

1.5.1 Words shown in *italics* have the meaning specified in section 4.

1.6 Interpretation

1.6.1 If a provision of this *Metrology Procedure* is inconsistent with the *Metering Code*, the *Metering Code* prevails to the extent of the inconsistency.

1.6.2 For the purpose of clarification, to the extent that this *Metrology Procedure* and the National Measurement Act are inconsistent, the National Measurement Act is to prevail.

1.6.3 The *Network Operator* may issue guidelines and procedures that clarify aspects of this *Metrology Procedure*.

1.6.4 Unless the contrary intention is apparent:

1. The Interpretation Act 1984 applies to the interpretation of this *Metrology Procedure*.
2. A reference in this *Metrology Procedure* to a document or a provision of a document includes an amendment or supplement to, or replacement of or novation of, the document or provision.
3. A reference in this *Metrology Procedure* to a person includes the person's executors, administrators, successors, and substitutes and permitted assigns.
4. Where italic typeface has been applied to some words and expressions in this *Metrology Procedure*, it is solely to indicate that those words or expressions may be defined in clause 4, *Definitions*, or elsewhere, and in interpreting this *Metrology Procedure* the fact that italic typeface has or has not been applied to a word or expression is to be disregarded.
5. Where information in this *Metrology Procedure* is set out in braces (namely "{" and "}"), whether or not preceded by the expression "Note", "Outline" or "Example", the information:
   i. is provided for information only and does not form part of this *Metrology Procedure*; and
   ii. is to be disregarded in interpreting this *Metrology Procedure*; and
   iii. might not reflect amendments to this *Metrology Procedure* or other documents or written laws.
6. "Including" and similar expressions are not words of limitation in this *Metrology Procedure*.
7. Meaning of 'publish.' If the *Network Operator* is required to "publish" a thing, the *Network Operator* must: place the thing upon an internet website under the *Network Operator*'s control; and send an electronic notice to each *Code Participant* advising the *Code Participant* that the thing has been placed on the internet website.

1.7 Commencement

1.7.1 The date of publication of the *Metrology Procedure* is ten days following approval by the *Authority*.

1.7.2 This *Metrology Procedure* comes into operation three months after the date of publication.

1.8 Metering Installation Components

1.8.1 The components of a *metering installation* covered by this *Metrology Procedure* are:

a) One or more metering *points;* and,

b) The *instrument transformers;* and,

c) The *measurement element;* and,

d) The *data logger;* and*,*

e) The *communications link;* and,

f) The associated wiring, connectors, fuses, mounting boards and housings.

1.8.2 This document also addresses the following associated services

a) *Meter data services* within the *communications link*

b) Testing and inspection

c) Management, maintenance and auditing

1.8.3 The primary components, their characteristics and associated service requirements have been itemised in the Schedules for the purpose of allowing the *Network Operator* to exercise discretion in a transparent manner, or to provide the information required by the *Metering Code* or *Market Rules.*

1.8.4 The information contained in the Schedules is largely a replication of the requirements in the *Metering Code* and Market Rules with practical clarification by the *Network Operator* where necessary.

2 Responsibility for Meter Provision

2.1 *Network Operator* is Responsible for Meter Provision

2.1.1 The *Network Operator* is responsible for the design, provision, installation and maintenance of *metering installations*.

2.2 Enhanced Technology Features

2.2.1 Where reasonably requested by a *Code Participant*, the *Network Operator* will provide *metering installations* with *enhanced technology* features.

2.2.2 *Metering installations* with *enhanced technology* features will only be used where they meet or exceed the standards required of the un-enhanced type 1-6 *metering installation* that would otherwise be used at the connection point under consideration.

2.2.3 Where a *meter* includes enhanced features more normally associated with a *meter* of a more advanced type, the normal provisions of the standard type of *meter* apply for all aspects other than the enhanced feature.

{For example, addition of communications capability to a type five *meter* does not mean that the *meter* should thereafter be treated as being of type 4. Rather it will continue to be treated as a type 5 *meter* in every respect except communications. }

2.2.4 Notwithstanding clause 2.2.3, a *meter* may be reported as a different type within the metering *database* where this is necessary to support the *enhanced technology feature*.

{For example, an interval capable type 6 *meter* has the accuracy and other requirements of a type 6 *meter* under this *Metrology Procedure* for metrology (in the dictionary sense) purposes. When used as an *accumulation meter* this makes no difference. However if the *meter* is reprogrammed to become an *interval meter* then to properly support and disseminate the interval *energy data* it may need to be processed and reported as a type 5 *meter* within the Western Power metering systems. From a *retailer* perspective it can be treated as a type 5 *meter* but the difference may be significant if a *meter* test is requested.

Thus,

Meter type	Treated as
Basic accumulation *meter*	Type 6
Interval capable *meter* read as accumulation	Type 6
Interval capable read as accumulation with communications	Type 6
Interval capable read as interval	Types 1-5 depending on other features
Interval capable with communications	Types 1-4 depending on annual consumption

}

2.2.5 If the *metering installation* includes a *data logger* then:

a) Where a *communication link* has been installed, the *metering installation* must include facilities for the on-site storage of *energy data* for a period of at least 35 calendar days from the time of the last successful read of the *meter*, or the maximum period between scheduled *meter* readings, whichever is greater.

b) Where a *communications link* has not been installed, the *metering installation* must include facilities for the on-site storage of two hundred days of *energy data*, or the maximum period between scheduled *meter* readings, whichever is greater.

{Note –the 200 days is a requirement shared across data streams. Thus 200 days of data could correspond to:

- *66 days in each of three data streams, or*
- *50 days in each of 4 data streams or*
- *200 days for a single data stream}*

2.2.6 Where a *metering installation* includes a *data logger* and no remote reading facility exists, or where remote communications has not been possible, then a manual visit will be scheduled prior to the end of the periods allowed for in 2.2.4 or as soon after as is reasonably possible.

*{Note – the intention here is that if communications fail then, where possible, someone will manually attend site to take a reading prior to the data being lost. Examples of where this may **not** be possible would be where the communications fails immediately prior to the 35 day limit and it is not feasible to physically attend site in the time remaining due to factors such as geographical remoteness. Under these circumstances the Network Operator would attempt to minimise data loss by attending site promptly}*

2.2.7 A *Network Operator* providing one or more *metering installations* with *enhanced technology* features must:

a) be licensed to use and access the metering software applicable to all devices being installed; and

b) be able to program the devices and set para*meter*s, including 'read only' and 'write' passwords.

2.2.8 Where signals are provided from the *metering installation* for the *user* or the *user's* customer use:

a) the *Network Operator* must ensure that the signals are isolated by relays or electronic buffers to prevent accidental or malicious damage to the *meter*; and

b) the *Network Operator* must provide the user or the *user's* customer with sufficient details of the signal specification to enable the *user* or the *user's* customer to comply with clause 2.2.8(c); and

c) customer must ensure that a device to be connected to the signal output is compatible with the signal.

2.2.9 If *metering installations* with *enhanced technology* are introduced to the *network* this *Metrology Procedure* will be amended if necessary to cater for other features of these *metering installations*.

2.3 Prepayment Meters

2.3.1 Where *prepayment meters* are installed:

a) they will be treated where reasonably possible as Type 6 accumulation *meter*s; and

b) they will be operated and maintained in accordance with good electricity practice.

2.3.2 Despite clause 2.3.1, a dispute or difference arising in connection with a *prepayment meter* will be handles under the provisions of clause 3.11, Disputes.

2.3.3 If *prepayment meters* that cannot be treated as Type 6 accumulation *meter*s are introduced to the *network* this *Metrology Procedure* will be amended where necessary to cater for other features of these *meter*s.

2.4 Metering Installation Components – Meter Provision

2.4.1 The requirements in this clause are applicable to types 1 – 4, type 5 and type 6 *metering installations*.

2.4.2 The *Network Operator* must ensure that the components, characteristics and requirements for *meter* provision for type 1 – 4, type 5 and type 6 *metering installations* are as shown in Schedules 1, 2 and 3 respectively.

2.4.3 Schedule 1 details the minimum requirements for *meter* provision for the type 1 – 4 *metering installations*, schedule 2 details the minimum requirements for type 5 *metering installations* and schedule 3 details the minimum requirements for type 6 *metering installations*.

2.4.4 Subject to clauses 2.4.2 and 2.4.3, *metering installations* which have been installed, or which are held in stock for the *Network Operator*, prior to the effective date of the initial *Metrology Procedure* and which do not meet the requirements in Schedules 1, 2 or 3 may be used at the discretion of the *Network Operator*.

2.4.5 The choice of *meter* type will be based on the historic or anticipated annual consumption and peak load at the connection point, as agreed with the retailer, and on the need for interval data and communications.

{Note: it is anticipated that routine agreement and discussion will not be required. I.e. that the retailer will indicate to Metering Services the circumstances under which they need to be consulted about the *meter*.}

2.4.6 An increase in annual or peak consumption which, in the opinion of the *Network Operator*, places the connection point into a higher type will result in a *meter* upgrade. Where annual consumption has decreased with time no *meter* change will result.

2.4.7 Where a *metering installation* includes a type 5 *meter* that is read as an *accumulation meter*, the *meter* will not be replaced by or, reconfigured to, an interval-read *meter* without the agreement of the *retailer*.

{Note: this is intended to address a number of historical *meter*s that are currently read as accumulation *meter*s but which might have been supplied with interval *meter*s if the current rules and processes had applied in the past. If it is necessary to replace such a *meter* it is important to the retailers that this replacement does not unexpectedly change the type of data they receive. }

2.5 Metrology Procedure Defines Minimum Rather Than Maximum Requirements

2.5.1 It should be noted that this document presents the minimum requirements and does not preclude a *meter* supplier, *Network Operator* or metering *data agent* from deploying products or developing processes that exceed or complement the requirements defined in this section, providing that such features are compatible with the requirements of the *Metrology Procedure*s. For example, the deployment of *meter*s with enhanced technology features or the future provision of interval *meter*s for connection points with low annual consumption.

2.6 Removal of Meters

2.6.1 From the commencement of this *Metrology Procedure*, the *Network Operator* must ensure that a type 1- 4 or type 5 *metering installations* are not replaced by a type 6 *metering installation,* unless agreed by all the relevant *Code Participants*.

2.7 Testing and Inspection of Meters

2.7.1 The *Network Operator* must ensure that *metering installations* are tested and inspected in accordance with Schedules 1, 2 and 3.

2.7.2 Clauses 2.7.3to 2.7.11 (inclusive) are to be regarded as the asset management strategy guidelines for the whole-current (direct connected) *meters* for the purpose of section 6.8(d) of the *Code*.

2.7.3 The *asset management plan* referred to in clause 2.7.2 must include, as a minimum, the requirements the Australian Standard 'AS1284 Part 13: In-service compliance testing'.

2.7.4 The *Network Operator* must ensure that an *asset management plan* is established and maintained for the testing and inspection requirements of whole-current (direct connected) *meters*.

2.7.5 For the purposes of the *asset management plan*, the whole-current (direct connected) *meters* must be divided into *testing classes*.

2.7.6 Where historical *meter* records permit, the *testing classes* referred to in clause 2.7.5 should consist of *meters* of the same year of manufacture and common design.

2.7.7 The *Network Operator* must ensure that a sampling plan is established and maintained in accordance with the *asset management plan* to ensure that each *testing class* of whole-current (direct connected) *meter*, and associated *data logger* (where the *data logger* is located at the metering point) for type 5 *metering installations*, is tested at least once in the first fifteen (15) years following manufacture and at least once in each subsequent five (5) year period.

2.7.8 For those whole-current (direct connected) *meters* for which new or amended pattern approval has been received from the National Measurement Institute, or for which new or amended type testing has been undertaken by a NATA accredited laboratory or overseas equivalent approved by the National Measurement Institute, the *Network Operator* must ensure that the sampling plan ensures that this *testing class* of *meter* is tested at least once in the first three (3) years following receipt of the new or amended pattern approval, or the new or amended type test certificate.

2.7.9 If the results from a sampling test carried out in accordance with a sampling plan described in clauses 2.7.7 and 2.7.8 demonstrate that the *testing class* of *meters* being sampled fails to meet the requirements of the sampling plan, then the *Network Operator* must ensure that all *meters* in that *testing class* are replaced or recalibrated within a reasonable period of time.

2.7.10 When determining the planned schedule for the replacement or recalibration of a *testing class* of *meter* in accordance with 2.7.9, the *Network Operator*, will consult with the affected *Code Participants*.

2.7.11 The *asset management plan* must include, but need not be limited to:

a) Records relating to *meter testing classes* and age of manufacture;

b) *Meter* test records for each *meter testing class*;

c) *Meter* test plan for each *meter testing class* based on *meter* quantity (sample size) and *meter* age;

d) Frequency of test;

e) Records of *meter* failures per *meter testing class*;

f) Planned replacement strategy based on age and/or performance;

g) Location of each *meter*; and

h) *Meter* registration number.

2.8 Installation of Meter

2.8.1 The *Network Operator* must ensure that when each *meter* and associated *data logger* (where the *data logger* is located at the metering *point*) is installed, it is checked to ensure that it:

a) Complies with the relevant requirements of Schedules 1-3, respectively subject to clause 2.4.4;

b) Has the optical port, communications port, and/or visual display located so that the optical port, communications port, and/or visual display can be readily accessed for *meter* reading.

2.8.2 Notwithstanding clause 2.8.1, *meter*s procured to a specification that conforms to schedules 1-3, and which is usually held as a standard stock item by the *Network Operator*, can be assumed to meet the requirements of Schedules 1-3 without further testing.

3 Responsibility for Energy Data Services

3.1 Overview

3.1.1 Energy data services covers all aspects of retrieving, storing and disseminating the *energy data* readings recorded by the *meter*.

3.2 Metering Installation Components – Energy Data Services

3.2.1 The *Network Operator* must ensure that the components, characteristics and requirements for energy data services for all *metering installations* are:

a) for *metering installations* of types 1-4, as described in Schedule 1 – Components of Types 1- 4 Metering Installations; and,

b) for *metering installations* of types 5, as described in Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services; and,

c) for *metering installations* of types 6, as described in Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services; and,

d) for *metering installations* of types 7, as described in Schedule 6 – Components of a Type 7 Metering Installation – Energy Data Services.

3.2.2 The Schedules referenced in clause 3.2.1detail the minimum requirements for *energy data services* for *metering installations*.

3.3 Meter Reading For Metering Installations

3.3.1 The *Network Operator* will ensure that for metering installations of types 1-4, interval energy data will be collected on a monthly basis, or, by agreement with the relevant retailer, daily.

3.3.2 The *Network Operator* will ensure that for metering installations of types 5, interval energy data will be collected on a monthly basis.

3.3.3 The *Network Operator* will ensure that for metering installations of types 6, energy data will be collected on a monthly or bi-monthly basis, as agreed between the *Network Operator* and retailer at the time of installation; or

3.3.4 Notwithstanding 3.3.1 and 3.3.2, the *Network Operator* may choose for operational or other reasons to disseminate the energy data for meter types 1-5 more frequently.

{Note: the *Network Operator* may choose for internal reasons to collect and issue data weekly for monthly read meters, as is common practice at present. However the Retailer would still only be charged for monthly reads.}

3.3.5 Where a type 6 meter is capable of recording both interval and accumulation energy data, it will be treated as an accumulation meter, unless otherwise agreed between the *Network Operator* and retailer.

3.3.6 When a retailer has requested that an interval-capable type 6 meter be treated as an interval meter, then the meter cannot revert to being read as an accumulation meter in the future.

3.3.7 The *Network Operator* and retailer may agree other reading frequencies for specific meters or classes of meters, as documented in a service level agreement.

3.3.8 For the purposes of clauses 3.3.1, 3.3.2 and 3.3.3, the meter reading cycle for a metering installation commences from the most recent meter reading prior to, or in conjunction with, the end-use customer transferring to a new retailer.

3.3.9 The *Network Operator* must ensure that energy data is collected from a meter or meter/associated data logger and this data is transferred to the relevant metering database, no later than two (2) business days after the scheduled reading date for that metering installation, or within the time frame specified in the applicable service level agreement.

{E.g. if the scheduled read date is a Friday on a normal working week then the data must be in the metering database by 23:59:59 on the following Tuesday (Two business days later).}

3.3.10 Where energy data is collected from a meter or meter/associated data logger by a user this data must be provided to the *Network Operator* no more than two (2) business days after collecting or receiving the data, or within the period specified in the applicable service level agreement.

3.3.11 The *Network Operator* must ensure that a schedule is developed and maintained to determine the scheduled reading dates for each metering installation in accordance with the applicable service level agreement. Not withstanding the provisions of the applicable service level agreement, the maximum interval between attempts to read each meter will be one calendar year.

3.3.12 The meter reading schedule for each calendar year for all network connection points will be published no later than the last day of the month of October preceding the start of the year under consideration.

{For example, the meter reading schedule for the year falling from 1st January 2008 to 31st December 2008 will be published on the Western Power website no later than 23:59 on 31st October 2007}

3.3.13 The *Network Operator* will accept requests for special meter reads in accordance with the provisions of the communication rules and will respond to valid requests within the response times specified in the applicable service level agreement.

3.3.14 The *Network Operator* must in all other respects arrange for any special meter reads, final meter reads or estimated reads to be undertaken in accordance with any relevant transfer rules or jurisdictional instruments which relate to meter reading.

3.3.15 Where energy data for metering installations of type 1-5 is gathered at a frequency greater than a trading interval it will be aggregated into trading intervals.

3.4 Validation And Substitution/Estimation of Energy Data

3.4.1 The *Network Operator* must ensure that *energy data* collected for a *metering installation* of types 1 to 5 in accordance with clause 3.3 is validated in accordance with the validation rules in Schedule 7 – *Metering Installation* Types 1-5 – Validation .

3.4.2 The *Network Operator* must ensure that *energy data* collected for a *metering installation* of type 6 in accordance with clause 3.3 is validated in accordance with the validation rules in Schedule 9 – Metering Installation Type 6 – Validation, Substitution and Estimation.

3.4.3 The *Network Operator* must ensure that *energy data* collected for a *metering installation* of type 7 in accordance with clause 3.3 is validated in accordance with the validation rules in Schedule 11 – *Metering Installation* Type 7 – Validation.

3.4.4 Where a *Code Participant* requests validation of data under clause 5.20 of the Code, the *Network Operator* will repeat the applicable tests specified in clauses 3.4.1, 3.4.2 or 3.4.3.

3.4.5 Where the *energy data* fails the validation tests under clauses 3.4.1, 3.4.2, 3.4.3, or 3.4.4 the *Network Operator* will review the validation failures to determine the cause of any apparently lost or erroneous *energy data* and take such corrective action as *Network Operator* believes is warranted. Such corrective action may include:

a) manual correction of the reading;

b) re-reading the *meter*;

c) placing the associated *meter installation* under test;

d) replacing the *metering installation*;

e) repairing the *metering installation*.

{Note –

- *There is always a manual review where validation fails.*
- *an example of where manual correction is appropriate would be the case where a review of a suspect reading reveals that the error is probably due to a transcription error such as the reversal of adjacent digits.*
- *an example of where a re-read may be appropriate is if it is still within the current billing cycle and the meter has remote reading capability or can be easily visited by a meter reader or other* metering *personnel.}*

3.4.6 Following the review under clause 3.4.5, except in the cases of 3.4.5 (a) and 3.4.5 (b), or where it has not been possible to successfully read the *meter*, the *Network Operator* may elect to substitute the *energy data* for the period under consideration.

3.4.7 Where data is required for market settlement purposes and a reading is not scheduled for the *meter* prior to the end of the settlement period, the *Network Operator* may estimate the *energy data* for the period under consideration.

3.4.8 For *metering installations* of types 1-5 the *Network Operator* must ensure that the *energy data* is substituted or estimated in accordance with Schedule 8 – Metering Installation Types 1-5 – Accumulation, Substitution and Estimation, where:

a) the network Operator has elected to perform substitution under clause 3.4.6; or

b) the network Operator has elected to perform estimation under clause 3.4.7; or

c) there has been a failure of the metering equipment; or,

d) an inspection or test on the metering equipment has established that the measurement uncertainty exceeds the specified standard for that class of *meter*.

3.4.9 For *metering installations* of type 6 the *Network Operator* must ensure that the *energy data* is substituted or estimated in accordance with Schedule 9 – Metering Installation Type 6 – Validation, Substitution and Estimation, where:

a) the network Operator has elected to perform substitution or estimation under clause 3.4.6; or

e) the network Operator has elected to perform estimation under clause 3.4.7; or

b) there has been a failure of the metering equipment; or,

c) an inspection or test on the metering equipment has established that the measurement uncertainty exceeds the specified standard for that class of *meter*.

3.4.10 For *metering installations* of type 7 the *Network Operator* must ensure that the *energy data* is substituted or estimated in accordance with Schedule 11 – Metering Installation Type 7 – Validation and Substitution, clause 15.2*,* where:

a) an audit under clause 15.1 of the information and algorithms used in the calculation of *energy data* for a Type 7 *metering installation* establishes that an error exists in the *energy data* calculation.

3.5 Calculation of Energy Data For Type 7 Metering Installations

3.5.1 The retailers and the *Network Operator* have agreed that type 7 consumption calculations will continue to be made by the methods and systems in place as of June 2006 for the foreseeable future. The method of substitution under this agreement is thus treated as type 74 under the *Metering Code* and this *Metrology Procedure*.

3.5.2 The metering installation and metering database associated with each type 7 meter are therefore the systems in use as of June 2006, or as agreed between those retailers with customers at type 7 metering installations and the *Network Operator*.

3.5.3 The *Network Operator* must ensure that energy data for a type 7 metering installation is calculated in accordance with Schedule 10 – Metering Installation Type 7 – Energy Calculation, type 74.

3.5.4 The *Network Operator* must ensure that the energy data for a type 7 metering installation, which is calculated in accordance with clause 5.6.1, is validated in accordance with Schedule 11 – Metering Installation Type 7 – Validation and Substitution, clause 15.1.

3.5.5 The *Network Operator* must ensure that the energy data is substituted in accordance with substitution method 74 as defined in Schedule 11 – Metering Installation Type 7 – Validation and Substitution, where the energy data calculated for a type 7 metering installation fails the validation test conducted in accordance with clause 3.5.4

3.5.6 The *Network Operator* must ensure that, where energy data for a type 7 metering installation is substituted in accordance with clause 3.5.5, affected Code Participants are advised that substituted data will be used for settlements purposes.

3.6 Data Storage

3.6.1 The *Network Operator* must provide a metering *database* containing *energy data* in respect of each types 1-5, 6 and 7 *metering installations*, in accordance with the requirements,:

a) for *metering installations* of types 1-5, as described in Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services; and,

b) for *metering installations* of types 6, as described in Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services; and,

a) for *metering installations* of types 7, as described in Schedule 6 – Components of a Type 7 Metering Installation – Energy Data Services.

3.6.2 For the avoidance of doubt, the *energy data* for a type 5 or type 6 *metering installation* is the data collected from the *meter* or associated data logger in accordance with clause 3.3 subject to clause 3.4, and/or the data that is estimated in accordance with clause 3.5.

3.6.3 The rights of access to the data held within the *metering database* are set out in clauses 4.8 and 7.6 of the *Code* and in clause 3.7.1 of this *Metrology Procedure*.

3.7 Information

3.7.1 The *Network Operator* must provide access to *energy data* to a *Code Participant* for each connection point at which the *Code Participant* supplies, generates or purchases electricity.

3.7.2 Where a communication link is installed for a *metering installation*, the *Network Operator* will provide a read-only password and connection details to the *Code Participants* who have access under clause 3.7.1

3.7.3 The *Network Operator* must provide access to *energy data* to the *IMO* for settlement and load forecasting purposes.

3.7.4 The *Network Operator* must provide access to *energy data* to the *Authority* for auditing and compliance purposes upon request.

3.7.5 For the purposes of clauses 3.7.1 to 3.7.4 access to *energy data* must be provided as follows:

a) where *energy data* for a type 1-6 *metering installation* has been collected in accordance with clause 3.3, and validated in accordance with clause 3.4, by 5.00 pm on the second business day after that *energy data* has been collected; or

b) where *energy data* for a type 1-6 *metering installation* has been substituted in accordance with clause 3.4, by 5.00pm on the second business day after that *energy data* has been estimated; or

c) where *energy data* for a type 7 *metering installation* has been calculated, validated and substituted in accordance with clauses 3.5 and 3.4 by 5.00pm on the second business day after that *energy data* has been calculated.

3.7.6 The *Network Operator must* ensure that access to the *metering installation* is secured from unauthorised access in line with clause 4.8.4(a) of the *Metering Code* and in line with good electricity and IT industry practice.

3.7.7 The *Network Operator must* ensure that access to the metering *database* is secured from unauthorised access in line with clause 4.8.4(a) of the *Metering Code* and in line with good electricity and IT industry practice.

3.8 Validation of Metering Database

3.8.1 The *Network Operator* must ensure that a sampling plan is established and maintained, in accordance with Australian Standards “AS1199: Sampling Procedures and Tables for Inspection by Attributes” or “AS2490: Sampling Procedures and Charts for Inspection by Variables for Percent Nonconforming” to validate that the data stored in the metering *database* with respect to a type 5 or type 6 *metering installation* is consistent with the data stored in the *meter* or *meter*/associated data logger.

3.8.2 The validation test must be conducted at a frequency in accordance with the sampling plan described in clause 3.8.1, which must not be less than once every twelve (12) months.

3.8.3 If there is an inconsistency between the data held in a *meter* or *meter*/associated data logger, and the data held in the metering *database*, the data in the *meter* or *meter*/associated data logger is to be taken as prima facie evidence of the *energy data* for that metering point.

3.8.4 The *Network Operator* must ensure that a sampling plan is established and maintained in accordance with Schedule 13 to validate that the data stored in the metering *database* with respect to a type 7 *metering installation* is consistent with the physical inventory.

3.8.5 A validation test must be conducted at a frequency in accordance with the sampling plan described in clause 3.8.4, which must not be less than once every twelve (12) months.

3.8.6 The *energy data* stored in a metering *database* for a type 7 *metering installation*, for an NMI, is consistent with the physical inventory if the error associated with calculating the energy value for the sample is within the accuracy requirement determined in accordance with clause 3.8.7. That is,

$$\Delta E = \frac{\sum_{i=1}^{n} m_i n_i}{\sum_{i=1}^{n} x_i y_i} - 1$$

Where,

ΔE	is the error associated with calculating the energy value for the sample geographic area.
m_i	is the agreed load of device type *i*, as per the *Load Table*.
n_i	is the actual number of devices of device type *i* in the sample geographic area.
x_i	is the agreed load of device type *i*, as per the *Load Table*.
y_i	is the actual number of devices of device type *i* in the sample geographic area , as per the *Inventory Table*.

3.8.7 The accuracy requirement for the *energy data* for a type 7 *metering installation*, based on the formula in clause 3.8.6, shall be +/-2.0% by a date determined by the *metrology coordinator* in consultation with the *Network Operator*. The accuracy requirement prior to this date will be determined by the *metrology coordinator* in consultation with the *Network Operator* and the affected *Code Participants* in a transition plan which will be developed when the *Inventory Table* and *Load Table* are first agreed and the accuracy of those initial tables has been determined by the *Network Operator*.

3.8.8 If there is an inconsistency between the data held in the metering *database* and the physical inventory, the physical inventory is to be taken as prima facie evidence of the actual data.

3.8.9 *Act*ions in event of non-compliance with accuracy requirements are set out in:

a) Schedule 1 – Components of Types 1- 4 Metering Installations, or

b) Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services, or

c) Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services, or

d) Schedule 6 – Components of a Type 7 Metering Installation – Energy Data Services.

3.9 Request for Testing of the Metering Installation

3.9.1 If requested by a *Code Participant*, the *Network Operator* must conduct a test to determine the consistency of data held in the metering *database* and data held in the *meter* or *meter*/associated data logger of a *metering installation*.

3.9.2 The *Network Operator* must make available the results of the test described in clause 3.9.1 to the *Code* Participant as soon as practicable.

3.9.3 Where the test undertaken in accordance with clause 3.9.1 determines an inconsistency, the *Network Operator* must pay the costs of, and associated with, that test.

3.9.4 Where the test undertaken in accordance with clause 3.9.1 determines no inconsistency, the *Code Participant* who requested the test under clause 3.9.1 must pay the costs of, and associated with, that test.

3.9.5 Where there is a discrepancy between:

a) *energy data* stored in the *meter* or *meter*/associated data logger; and

b) *energy data* stored in the metering *database* in respect of the respective *meter* or *meter*/associated data logger, the *energy data* stored in the *meter* or *meter*/associated data logger is prima facie evidence of the amount of electricity supplied to that metering point.

3.9.6 If requested by a *Code Participant*, the *Network Operator* must conduct a test to determine the accuracy of data held in the metering *database* and the physical inventory of a type 7 *metering installation*.

3.9.7 The *Network Operator* must make available the results of the test described in clause 3.9.6 to the *Code* Participant as soon as practicable.

3.9.8 Where the test undertaken in accordance with clause 3.9.6 determines an error between the data held in the metering *database* and the physical inventory is more than the accuracy requirement as set out in clause 3.8.7, the *Network Operator* must pay the costs of, and associated with, that test.

3.9.9 Where the test undertaken in accordance with clause 3.9.6 determines that the error between the data held in the metering *database* and the physical inventory is within the accuracy requirement as set out in clause 3.8.7, the *Code* Participant who requested the test under clause 3.9.6 must pay the costs of, and associated with, that test.

3.9.10 Where there is a discrepancy between the data held in the metering *database* and the physical inventory, the physical inventory is to be taken as prima facie evidence of the actual data.

3.9.11 If requested by a *Code* Participant, the *Network Operator* must, prior to any test being undertaken in accordance with clause 3.9.1 or clause 3.9.6, provide an estimate of the costs of, or associated with, that test.

{Note – the service level agreement dictates the charges associated with performing a test on the meter itself. The clauses in this section deal with different tests – namely, validation of the data in the database against the meter – that are not covered by the standard fees and which will be costed on a case by case basis.}

3.10 Procedure Changes

3.10.1 This *Metrology Procedure* may be changed in accordance with Part 6 of the *Metering Code*.

3.11 Disputes

3.11.1 The *Network Operator* will appoint an *Account Manager* to be available to *Code Participants* to contact during normal business hours. Each *Metering Code Participant* is also to nominate a contact person during *business hours*.

3.11.2 The *Manager of* Metering *Services* will be ultimately accountable for the relationship of the *Network Operator* with the *Metering Code Participants*.

3.11.3 Any disputes associated with this *Metrology Procedure* will be addressed in the first instance to the Account Manager for resolution. The *Account Manager* will investigate the dispute and provide a response within 10 *business days* of any dispute being notified in writing.

3.11.4 In the event that an issue cannot be resolved to the *Code Participant's* satisfaction, the matter should then be escalated to the *Manager of* Metering *Services*, again in writing, who will respond to the complaint within 10 business days.

3.11.5 In the event that the issue remains unresolved following consideration by the *Manager of* Metering *Services*, then the dispute should follow the dispute resolution process set out Part 8, Dispute Resolution, in the *Metering Code*.

3.12 Disaster Recovery

3.12.1 The *Network Operator* must ensure that disaster recovery procedures are prepared and developed in relation to the *energy data* for *metering installations* and the information stored in the metering *database.*

3.12.2 The *Network Operator* must ensure that disaster recovery procedures are prepared and developed in relation to *energy data* for *metering installations*, including the metering *database*. A disaster recovery guideline must seek to ensure that, within two business days after the day of any disaster:

a) the metering *database* can be rebuilt; and

b) *energy data* can be provided to the relevant *Code Participants* including *energy data* for any of the days during which the *Network Operator* was affected by the disaster.

{NOTES:

- *Failures necessitating the implementation of the disaster recover guidelines may include, for example, the failure of components of the computer systems hosting the* metering *database, a fire or other natural disaster impacting the data processing centre, etc.*
- *The basic principle is that services should be restored within two business days and no energy data should be lost as a result of the* metering *database being unavailable.*
- *However, it is not practical to implement redundancy and data back up facilities for every metering installation database/data logger. Thus if a physical disaster were to befall a metering installation then some data loss would occur. Under these circumstances substitution/estimation would be utilised to provide energy data values covering any such periods}*

3.12.3 The disaster recovery guideline must be prepared in accordance with:

a) the relevant requirements for dispute resolution in Part 8 of the *Code*;

b) the requirements for the repair of an outage or malfunction to a *metering installation* in clause 3.11 of the *Code*; and

c) guidelines for the substitution, estimation, and calculation of *energy data*, provided in clause 3.4 of this *Metrology Procedure*; and

d) good electricity and information technology industry practice.

3.12.4 The disaster recovery guidelines must be made available to *Code Participants* upon request.

4 Definitions

4.1.1 Within this procedure the following definitions apply:

a) AS – Australian Standard;

b) ISO – International Standards Organisation;

c) IEC – International Electrotechnical Commission.

4.1.2 Terms defined within the *Metering Code* have the same meaning in this *Metrology Procedure,* except as defined in the table below.

Phrase/term	Meaning
"access arrangement"	has the meaning given to it in the *Access Code*;
"Access Code"	means the *Code* made by the Minister under Part 8 of the *Act*.
"access contract"	means an agreement between a *Network Operator* and a person for the person to have 'access' (as defined in section 103 of the *Act*) to 'services' (as defined in section 103 of the *Act*) on a network.
"Account Manager"	Is the person appointed by the *Network Operator* under clause 3.11.1 as the main contact for *Code Participants.*
"accumulated energy data"	is to be expressed as a measure of *energy* over time, and means a measurement (including an estimated or substituted measurement) of the production or consumption of electricity at a metering *point*, which is accumulated for a period longer than a trading interval.
"accumulated energy register"	means the visible indication displayed on an *accumulation meter*, or the memory location within the *meter*, that records *accumulated energy data*.
"accumulation meter"	means a *meter* that measures *accumulated energy data* and records it in one or more *accumulated energy register*s.
"Act"	means the Electricity Industry Act 2004 (WA).
"active energy"	means a measure of electricity, being the time integral of the product of voltage and the in-phase component of electric current flow across a metering *point* expressed in Watt hours (Wh) and/or multiples thereof.
"apparent energy"	means a measure of electricity, being the time integral of the product of voltage and the electric current flow across a metering *point* expressed in Volt Amp hours (Vah) and or multiples thereof.
"applications and queuing policy"	means that part of the Western Power Access Arrangement defining the applications and queuing policy.
"AS"	followed by a designation means a standard so designated published by Standards Australia Limited and current as at the *Metering Code* commencement date.
"asset management plan"	means the document established under clause 2.7.4 detailing the testing and inspection requirements for whole current *meters*. At May 2006, this requirement is fulfilled by the Metering Services Metering Management Plan , as published from time to time by the *Network Operator*.

Phrase/term	Meaning
"associate"	has the meaning given to it in the Access *Code*. {Note: At the time this *Code* was made, the definition in the *Access Code* was: " 'associate', in relation to a person and subject to section 13.2 [of the *Access Code*, which extends the meaning of 'associate' to include any other business of the service provider], has the meaning it would have under Division 2 of Part 1.2 of the Corporations *Act* 2001 of the Commonwealth if sections 13, 14, 16(2) and 17 of that *Act* were repealed, except that a person will not be considered to be an associate of a service provider solely because that person proposes to enter, or has entered, into a contract, arrangement or understanding with the service provider for the provision of a covered service." At the *Code* commencement date, the following are examples of persons who are associates of a body corporate under the Corporations *Act* 2001 (Cth): • a director or secretary of the body corporate; and • a related body corporate of the body corporate; and • another body corporate that can control or influence the composition of the board or the conduct of the affairs of a body corporate.}
"Attachment Point"	means a point on the *network* at which *network assets* are *connected* to assets owned by another person.
"Authority"	means the Economic Regulation *Authority* established under the Economic Regulation *Authority Act* 2003 (WA).
"average daily consumption"	for a metering *point* is to be expressed in energy units per day, and means a measurement (including an estimated or substituted measurement) of electricity production or consumption over a period at the metering *point*, divided by the number of days in the period.
"business day"	means any day that is not a Saturday, a Sunday or a public holiday throughout Western Australia.
"business hours"	means the hours from 08:00 to 17:00 on a *business day.*
"check metering installation"	means a *metering installation* used as the source of *energy data* for validation and substitution purposes but not routinely used as a source of billing data.
"checksum"	means a single digit numeric identifier that is calculated to reduce the frequency of NMI data entry errors.
"Code of Conduct"	means the Code made by the Minister under Schedule 3, section 1 of the *Act*.
"Code"	means the Electricity Industry *Metering Code* 2005.
"Communication Rules"	means the rules governing the file formats, protocols and timeframes for the communication of information and data between *Code* participants, which have been approved by the *Authority*
"communications link"	means all communications equipment, processes and arrangements which facilitate the collection of *energy data* from a *data logger* or a *measurement element* so as to enable a remote interface to be established that lie: a) if the *data logger* is internal to the device containing the *measurement elements* — between the *data logger* and the telecommunications network; and b) if the *data logger* is external to the device containing the *measurement elements* but is located at the same site — between the *meter* and the *data logger* and between *data logger* and the telecommunications network; and c) if the *data logger* is not located at the same site as the device containing the *measurement elements* — between the *meter* and the telecommunications network.
"connect"	means to form a physical link to or through a *network*.

Phrase/term	**Meaning**
"connection point"	means an *exit point* or an *entry point* identified or to be identified as such in an electricity transfer access contract.
"contact details"	means the notified electronic communication address, notified facsimile number, notified postal address and notified telephone number of a *Code Participant*.
"covered network"	has the meaning given to it under the *Access Code*; {Note: At the time this *Code* was made, the definition in the *Access Code* was: " "covered network" means a network that is covered."}
"current transformer", or "CT"	means a transformer for use with *meters* and protection devices in which the electric current in the secondary winding is, within prescribed error limits, proportional to and in phase with the electric current in the primary winding.
"current user"	means the *user* recorded as such in the *registry*;
"current"	in connection with the flow of electricity, means the flow of electricity in a conductor.
"Customer Transfer Code"	means the *Code* made by the Minister under Part 8 of the *Act*.
"customer"	has the meaning given in section 3 of the *Act*.
"data logger"	means a *metering installation* database, metering *database* or a device that collects electronic signals from a *measurement element* and records interval *energy data*. {Note: A *data logger* may contain data storage capability, it be a separate item of equipment and/or it be combined with the energy measuring components within one physical device or it may be a combination of the foregoing elements.}
"data stream"	means a stream of *energy data* or metering data associated with a metering *point*, as represented by an NMI and a NMI suffix. A NMI can have multiple data streams.
"data"	means *energy data* or *standing data*.
"day"	means unless otherwise specified, the 24 hour period beginning and ending at midnight Western Standard Time (WST).
"demand"	Is the power requirement in a period expressed in kW. E.g. if the consumption in a period is 1kWh and the period under consideration is half an hour long then the demand is 2kW.
"dispute"	means any dispute or difference arising in respect of any matter under or in connection with this *Code* between any *Code* participants, the subject of matter of which is not also an access dispute under the *Access Code*, a dispute under the *Market Rules*, a dispute or a complaint under the *Code* of Conduct (For the Supply of Electricity to Small Use Customers or a dispute under the Customer Transfer *Code*.
"distribution connection"	means a point at which electricity is transferred to or from the distribution system.
"distribution system"	has the meaning given to it in the *Act*.
"electric"	Of, relating to, producing, or operated by electricity.
"electricity networks corporation"	means the body corporate established under section 4 of the Electricity Corporation *Act* 1994.
"electricity"	has the meaning given to it in the *Act*.
"electronic":	in relation to connection with a *meter*, means the transfer of information into or out of the *meter* by way of a telecommunications network for the delivery of *energy data* or pulsing signals or other widely accepted communications protocols used for the transfer of data between computerised equipment.

Phrase/term	**Meaning**
"energy data services"	means the services related to the determination, processing or storage of *energy data*.
"energy data"	means *interval energy data* or *accumulated energy data*.
"energy"	means *active energy* and/or *reactive energy* or both as applicable.
"energy units"	means Wh, VAh or VARh as appropriate.
"enhanced technology"	In relation to a *metering installation*, means evolving technologies that provide the *metering installation* with advanced features over and above the standard specified for installations of type 1-6; for example, those features described in Division 3.4 of the *Metering Code*.
"entry point":	means a single, indivisible (except as allowed under the *applications and queuing policy*) point, that for purposes under the *access arrangement* involving the transfer of electricity, is deemed to consist of a single *attachment point*, *connected* or to be *connected* to a *user's connection point*, with a single *meter* (regardless of the actual configuration of *network assets* making up the *entry point*), at which electricity is more likely to be transferred into the *network* than out of the *network*.
"estimate"	means an estimate calculation of *energy data* electricity production or consumption at a metering point for a future period, such calculation being made in compliance with the schedules to this *Metrology Procedure*..
"estimated energy data"	means the data that results from an estimation of electricity where the data applies to a trading interval or a period in excess of a trading interval.
"exit point":	means a single, indivisible (except as allowed under the *applications and queuing policy*) point, that for purposes under the *access arrangement* involving the transfer of electricity, is deemed to consist of a single *attachment point*, *connected* or to be *connected* to a *user's connection point*, with a single *meter* (regardless of the actual configuration of *network assets* making up the *entry point*), at which electricity is more likely to be transferred out of the *network* than into the *network*.
"General Purpose"	means the term applied by the National Measurement Institute constituted under Part 3 of the National Measurement *Act* to refer to the classification of a *meter*.
"generating plant"	in relation to a *connection point*, means all equipment involved in generating electricity.
"generator"	means a person who generates electricity who holds (or but for an exemption order under section 8 of the *Act* would be required by section 7 of the *Act* to hold) a generation licence or integrated regional licence under Part 2 of the *Act* for either or both of the construction and operation of generating works, and if any enactment (including regulations made under section 31A of the Electricity Corporation Act 1994) has the effect of deeming such a licence to be held by a part of the person, means that part.
"good electricity industry practice"	means the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.
"historical energy data"	means *energy data* that relates to one or more previous *meter*-reading periods.
"IMO"	means the Independent Market Operator appointed under the *Market Rules* Part 9 of the *Act*.
"incoming retailer"	has the same meaning as in the *Customer Transfer Code*.
"instrument transformer"	means either a *CT* or a *VT*.

Phrase/term	**Meaning**
"interval energy data"	is to be expressed in *energy units* or multiples thereof, and means a measurement (including an estimated or substituted measurement) of the production or consumption of electricity production or consumption at a metering *point* which is accumulated for each *trading interval*, or such sub-interval as has been previously agreed between the *Network Operator* and relevant *Code* Participant.
"interval meter"	means a *meter* that measures interval *energy data* and records it in a *data logger*.
"life support equipment"	has the meaning given to it in the *Code of Conduct* .
"load"	means the amount of electrical power energy transferred out of a network at a connection point at a specified time or across a specified period.
"maintain"	includes (as necessary and as applicable) renew, replace or update.
"Manager of Metering *Services"*	is the officer appointed by the *Network Operator* to carry overall responsibility for the provision of metering *services* for the *network*.
"market customer"	means a rule participant registered as a market customer under clauses 2.28.10, 2.28.11 or 2.28.13 under Chapter 2 of the *Market Rules*.
"market generator"	means a rule participant registered as a market generator under clauses 2.28.6, 2.28.7, 2.28.8 or 2.28.13 under Chapter 2 of the *Market Rules*.
"market rules"	has the meaning given to it in the *Act*.
"market"	means the wholesale electricity market established under Part 9 of the *Act*.
"measurement element"	means an energy measuring component of a *meter* which converts electricity into either or both of: a) an electronic signal; and b) a mechanically recorded electrical measurement.
"meter"	a device [complying with the relevant requirements of the AS 1284 series of standards] which measures and records the production or consumption of electrical energy, electricity production or consumption.
"metering *data agent"*	of a *Network Operator* for a network means the body appointed the *Network Operator*'s metering data agent for the network in accordance with the *Metering Code*.
"meter reading period"	For past dates, is the period between the date of a *meter* reading and the date of the previous *meter* reading. For future dates, is the period between the scheduled date of a *meter* reading and the previous scheduled or actual *meter* read.
"metering *database"*	means a database containing the *registry* and *energy data*.
"metering *equipment"*	means one or more parts of a *metering installation*.

Phrase/term	Meaning
"metering installation"	means the equipment, processes and arrangements for the purpose of metrology which lie between: at one boundary, either: a) for *a connection point* of Type 1 to 6 — the metering *point*; or b) for a *connection point* of Type 7 — the *connection point*; and at the other boundary, either: a) if a telecommunications network is used for the delivery of *energy data* from the *connection point* or metering *point* — the point of connection to the telecommunications network; or b) if there is no such telecommunications network — the interface port of either the *meter* or *data logger* or both.
"metering *point*"	means a) for types 1-6, the point at which electricity is measured by a revenue *meter* b) for a type 7 *meter*, the connection point.
"metering *protocol*"	A document required under the WA Electricity Market Rules, Part 8.7. This Metrology Procedure document meets the requirements for the metering protocol and will act as the WA Electricity Market metering protocol.
"metering *service order*"	has the meaning given to it in the *Metering Code*.
"metering *service*"	means activities that are performed by or on behalf of the *Network Operator* or its metering *data agent* and are related to the provision of *metering installations*, *standing data* and *energy data*.
"metrology coordinator"	means the officer appointed by the *Network Operator* to assume responsibility for maintaining and enforcing the *Metrology Procedure.*
"Metrology Procedure"	means this document, the Western Australian Electricity Market Metrology Procedure for *Metering installations*.
"metropolitan area"	means: the region described in the Third Schedule to the Metropolitan Region Town Planning Scheme *Act* 1959; and a) the local government district of Mandurah; and b) the local government district of Murray. c) the areas constituted by: d) the townsite of Albany, in the local government district of City of Albany; and e) the townsite of Bunbury, in the local government district of City of Bunbury; and f) the townsite of Geraldton, in the local government district of City of Geraldton; and g) the townsites of Kalgoorlie and Boulder, in the local government district of City of Kalgoorlie-Boulder; and h) the townsite of Karratha, in the local government district of Shire of Ashburton; and i) the townsites of Port Hedland and South Hedland, in the local government district of Town of Port Hedland.

Phrase/term	**Meaning**
"model service level agreement"	in relation to a *Network Operator*'s network, means: a) if the network is a covered network with an *access arrangement*— the part or parts of the *access arrangement* which deal with metering as a "supplementary matter" under the *Access Code*; and b) otherwise — a *model service level agreement* approved by the *Authority* under the provisions of the *Metering Code*.
"National Measurement Act"	means the National Measurement *Act* 1960 (Cth) and any regulations made under that *Act*.
"National Metering *Identifier", or "NMI"*	means the reference number required by the *Metering Code*, which uniquely identifies a *connection point* and which is issued under the Western Australian NMI Allocation Procedures {WP DMS reference # 2300622}.
"Network Operator"	in relation to a network means a person who holds (or but for an exemption order under section 8 of the *Act* would be required by section 7 of the *Act* to hold) a distribution licence, integrated regional licence or transmission licence under Part 2 of the *Act* for either or both of the construction and operation of the network, and if any enactment (including regulations made under section 31A of the Electricity Corporation *Act* 1994 (WA)) has the effect of deeming such a licence to be held by a part of the person, then means that part.
"network"	means the transmission system, distribution system or both, as applicable, operated by a *Network Operator*.
"operational data"	means *energy data* that is not obliged to have its accuracy and quality determined obtained via a system used to control and operate a network and the generating plant connected to a network.
"power factor"	means the ratio of the *active energy* to the *apparent energy* at a metering *point.*
"reactive energy"	means a measure in volt-ampère reactive hours (varh) of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of electric current flow across a connection point.
"registered metering installation provider"	means a person registered by a *Network Operator* in accordance with the *registration process* to undertake some or all of the Activities relating to the installation of *metering installations*, and who has not been deregistered under the *registration process*.
"registration process"	means the approved *registration process* established by a *Network Operator* and approved by the *Authority* under the provisions of the *Metering Code*.
"registry"	means a registry containing standing data in accordance with the *Metering Code*.
"related body corporate"	in relation to a body corporate, means a body corporate that is related to the first mentioned body corporate under the Corporations *Act* 2001 of the Commonwealth.
"Responsible Person"	Means the person who has responsibility for the provision of a *metering installation* for a particular *connection point*.
"retailer"	means a person who holds (or but for an exemption order under section 8 of the *Act* would be required by section 7 of the *Act* to hold) a retail licence or integrated regional licence under Part 2 of the *Act* for the sale of electricity to customers, and if any enactment (including regulations made under section 31A of the *Electricity Corporation Act* 1994 (WA)) has the effect of deeming the relevant licence to be held by a part of the person, then means that part.
"revenue meter"	means the *meter* that is used for obtaining the primary source of *energy data*.
"rule participant"	means a member of the class of persons as set out in clause 2.28.1 of the *Market Rules*.
"SCADA"	means Supervisory Control and Data Acquisition.

Phrase/term	Meaning
"scheduled meter reading date"	means the date scheduled for the next scheduled *meter* reading.
"scheduled meter reading"	means an actual *meter* reading on a cycle that equates to the a customer's billing cycle.
"service level agreement"	means a written agreement that sets out the terms and conditions under which a *Network Operator* must provide metering services to a user, whether or not that agreement also contains other provisions governing the parties' rights, liabilities and obligations.
"standing data"	means the periodically updated information about a *connection point* that is maintained in accordance with the *Metering Code* and the associated *Communication Rules*.
"substitute"	means the a substitution of *energy data* obtained from an actual *meter* reading with *energy data* obtained in accordance with the data substitution procedures defined in clause 4.4 under the circumstances described in the *Metering Code*.
"supply"	means the delivery of electricity.
"testing class"	means a collection of *meter*s of the same physical type that are treated as a single class for testing purposes.
"trading interval"	means a 30 minute period ending on the hour (WST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time.
"transfer"	in relation to a customer, has the meaning given to it in section 1.3 of the *Customer Transfer Code*.
"transformer"	means a plant or device that reduces or increases alternating voltage or electric current.
"transmission connection"	means a point at which electricity is transferred to or from the transmission system.
"transmission system"	has the meaning given to it in the *Act*.
"user"	[in respect of a *connection point*] means a person who has an *Access Contract* in respect of the *connection point* for the transfer of electricity [at the *connection point*].
"validation"	means validation in accordance with this *Metrology Procedure*.
"voltage"	means the electric force or electric potential between two points that gives rise to an electric current.
"voltage transformer" or "VT"	means a transformer for use with *meter*s and protection devices in which the voltage across the secondary terminals is, within prescribed error limits, proportional to and in phase with the voltage across the primary terminals.

5 Schedule 1 – Components of Types 1- 4 Metering Installations – Meter Provision

Ref.	Metering equipment components	Metering equipment characteristics	Requirement	*Metering Code* Clause or Table	Applicable *Metering installation* Type
5.1	Connection point	Metering Point	Electricity flowing through the connection point is to be greater than 1,000 GWh per annum.	Table 3	Type 1
5.2			Electricity flowing through the connection point is to be greater than 100 but less than 1,000 GWh per annum.	Table 3	Type 2
5.3			Electricity flowing through the connection point is to be greater than 0.75 but less than 100 GWh per annum.	Table 3	Type 3
5.4			Electricity flowing through the connection point is to be greater than 300 but less than 750 MWh per annum.	Table 3	Type 4
5.5		*Metering installation*	Metering point must have two separate *metering installations*, a "revenue" *metering installation* and a "check" *metering installation*.	3.13(2) Table 1	Type 1
5.6			Metering point must have, a "revenue" *metering installation* and either a "partial check" *metering installation* or a "check" *metering installation*.	3.13(2), Table 1	Type 2
5.7			No "check" *metering installation* required.	3.13(2), Table 1	Type 3 - 6
5.8			The revenue metering point is to be located as close as practicable to the connection point.	3.5(4)	Type 1 - 6
5.9			The *meter* is to be mounted on an appropriately constructed panel.	3.5	Type 1 - 6
5.10		Overall accuracy	Overall accuracy for a *metering installation* shall be no greater than 0.5% for *Active energy* and 1.0% for reactive *energy*.	Table 3 & 4	Type 1
5.11			Overall accuracy for a *metering installation* shall be no greater than 1.0% for *Active energy* and 2.0% for reactive *energy*.	Table 3 & 5	Type 2
5.12			Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy* and 3.0% for reactive *energy*.	Table 3 & 6	Type 3
5.13			Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy*.	Table 3 & 7	Type 4

5.14			High voltage connection points with an annual consumption of less than 750 MWh per annum must meet the accuracy requirements for a type 3 *metering installation*		Type 4
5.15		Testing facilities	Suitable isolation facilities are to be provided to facilitate testing and calibration of the *metering installation*.	3.12(3)	Type 1 - 6
5 .16		Check metering	A separate check *metering installation* is required.	3.12(2), Table 1	Type 1 - 2
5.17			Check *metering installation* shall use separate current transformer cores and separately fused voltage transformer secondary circuits preferably from separate secondary windings	3.13(2) Table 1	Type 1 - 2
5.18			Check *metering installation* may be supplied from secondary circuits used for other purposes and may have a lower level of accuracy than the revenue installation (0.5%) but must not exceed 1.0%	3.13(4)(a)	Type 1 - 2
5.19			Where the “check” *metering installation* duplicates the “revenue” *metering installation* and accuracy level, the average of the two validated data sets will be used to determine the energy measurement.	3.13(5)	Type 1 - 2
5.20	Instrument Transformers				
5.21		Current transformer	The accuracy of the current transformer is to be in accordance with class 0.2.	Table 3	Type 1
5.22			The accuracy of the current transformer is to be in accordance with class 0.5.	Table 3	Type 1 - 5
5.23			The current transformer core and secondary wiring associated with the revenue *meter* may not be used for other purposes.	3.12(b)	Type 1 - 5
5.24			New current transformers must meet the relevant requirements of AS 60044.1 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.12(2)	Type 1 - 5
5.25			Current transformers in service at the *Code* commencement date that do not comply with the accuracy requirements are acceptable providing the overall accuracy of the installation meets *Code* requirements for the applicable type *metering installation*.	3.14(3) Table 3	Type 1 - 5
5.26		Voltage transformer	The accuracy of the voltage transformer is to be in accordance with class 0.2.	Table 3	Type 1
			The accuracy of the voltage transformer is to be in accordance with class 0.5.	Table 3	Type 2 -3

5.27			If separate secondary windings are not provided, then the voltage supply to each *metering installation* must be separately fused and located in an accessible position as near as practical to the voltage transformer secondary winding.	3.12(d)	Type 1 - 3
5.28			New voltage transformers must meet the relevant requirements of AS 60044.2 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurements *Act*.	3.12(2)	Type 1 - 3
5.29			Voltage transformers in service at the *Code* commencement date that do not comply with the accuracy requirements are acceptable providing the overall accuracy of the installation meets *Code* requirements for the applicable type *metering installation*.	3.14(3)	Type 1 - 3
5.30			Secondary wiring must be by the most direct route and the number of terminations and links must be kept to a minimum.	3.12(1)(f)	Type 1 - 3
5.31			• 2.5 mm² cable is required for current transformer secondary wiring. • 1.5 mm² cable is required for voltage transformer secondary wiring		Type 1 - 5
5.32			The incidence and magnitude of burden changes on any secondary winding supplying the *metering installation* must be kept to a minimum.	3.9(3)	
5.33		Performance	Metering data is required for all trading intervals within the time agreed with the relevant retailers at a level of availability of at least 99% per annum for instrument transformers	3.11(1)(a)	
5.34		Outages	If an outage or malfunction occurs to an instrument transformer, repairs must be made as soon as practicable.	3.11(2)	
5.35	Measurement element				
5.36		Design standard	*Meter*s must meet the relevant requirements of AS1284 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.1	Table 1 - 6
5.37		Design Standard	*Meter*s in service at the *Code* commencement date whose accuracy does not meet *Code* requirements may remain in service for as long as the overall accuracy of the installation complies with the overall accuracy for a type of *metering installation*.	3.14	
5.38			*Meter*s must be capable of separately registering and recording flows in each direction where bi-directional *Active energy* flows.	3.16(1)(b)	
5.39		Accuracy	The accuracy of the Active and reactive measurement elements is to be class 0.2 and class 0.5 respectively.	Table 3	Type 1
5.40			The accuracy of the Active and reactive measurement elements is to be class 0.5 and class 1.0 respectively.	Table 3	Type 2

5.41			The accuracy of the Active and reactive measurement elements is to be class 1.0 and class 2.0 respectively.	Table 3	Type 3
5.42			The accuracy of the Active element is to be class 1.0	Table 3	Type 4 - 5
5.43		Visible display	To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2(1)	
5.44		Location	The revenue metering point is located as close as practicable to the connection point.	3.5(4)	
5.45		Security	The measurement element must be secure and associated links, circuits and information storage and processing systems must be secured by means of seals or other devices approved by the *Authority*.	3.8	
5.46		Storage	The measuring device must store Active and reactive *energy data* in a data logger. The data logger can be external or internal to the measuring element.	3.5(2)Table 3	Type 1 - 3
5.47			The measuring device must store *Active energy data*. The data logger can be external or internal to the measuring element.		Type 4 - 5
5.48		Access to data	Access to the visible display is to be provided without unreasonable restriction.	3.2(1)	
5.49			Access to the electronic signal from the measurement element is secured. Relays or electronic buffers to prevent accidental or malicious damage to the *meter* must isolate interfaces to customer equipment.	3.23	
5.50			Access to the electronic signal for use in evolving technologies is to be discussed with the *Network Operator*.	3.4	
5.51			Alteration to the original stored data in a *meter* is not permitted except during on-site accuracy testing.	5.21(12)	
5.52		Outages	If an outage or malfunction occurs to a measurement element or associated secondary wiring, repairs must be made as soon as practicable.	3.11	
5.53	Data logger				
5.54		Design standard	Any programmable settings available within a *metering installation*, data logger or any peripheral device, which may affect the resolution of displayed or stored data, must meet the relevant requirements of AS 1284 and must comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.10	
5.55		Location	The data logger may be located within the same housing as the measurement element or in a separate housing.	1.3	
5.56			The data logger may be located at the same site as the measuring element or at a remote site.	1.3	

5.57		Security	The data logger is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Authority*.	3.8	
5.58		Processing of data	Data relating to the amount of Active and reactive *energy* passing through a connection point must be collated into trading intervals.	3.16(3)	
5.59		Time function	The data logger clock is to be referenced to Western Australian Standard Time and maintained to a standard of +/- 5 seconds.	Table 3	Type 1 - 5
5.60		Storage	The data logger is to have the capability of storing energy data for a period of at least 35 days.	3.16(c), 3.21(2)	Type 1 - 5
5.61			A *Network Operator* must retain *energy data* in its metering *database* for each metering *point* on its *network* for the periods specified in section 4.9 of the *Metering Code.*	4.9	Type 1 - 6
5.62		Access to data	Alteration to the original stored data in a data logger is not permitted except during on-site accuracy testing.	5.21(12)	
5.63		Performance	Energy data is required for all trading intervals a level of availability of at least 99% per annum from the data logger.	3.11(a)	
5.64		Outages	If an outage or malfunction occurs to a data logger, repairs must be made as soon as practicable.	3.11(2)	
5.65	Communication link	Location	The electronic connection between the data logger and the telecommunications network boundary is classified as a communications link.	1.3	
5.66		Equipment	A communications link may consist of a metallic cable connecting to the telecommunications network and require isolation equipment, modem and associated connections	3.3(3)	
5.67			A communications link may include a radio, communications system, a microwave communications system or a satellite communications system or a combination of systems	3.3(3)	
5.68			A communications link may include a metering database.	3.3(3)	
5.69		Modem	Used to connect the *metering installation* to the telecommunications network at a data logger or metering database.		
5.70		Security	The communication link is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Authority*.	3.8	
5.71		Access to data	The *metering installation* must be capable of remote electronic access	3.6	Type 1 - 4
5.72			The *metering installation* must be capable of local electronic access	4.8	Type 5

5.73			To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	4.5	Type 1 - 6
5.74			The data held in the *metering installation* is to be protected from direct or remote electronic access by suitable password and security controls.	4.8(3), 4.8(4)(a)	Type 1 - 6
5.75		Performance	Energy data is required for all trading intervals at a level of availability of at least 95% per annum from the communications link.	3.11(b)	Type 1 - 5
5.76		Outages	If an outage or malfunction occurs to a communications link, repairs must be made as soon as practicable in accordance the applicable service level agreement.	3.11(2)	Type 1 – 6
5.77	Testing and inspection				
5.78		Purchase of metering equipment	At present National Measurements Institute regulations exempts Utility *Meter*s from the National Measurements *Act*. Whilst the exemption is in place • All new purchased current transformers must comply with Australian Standard AS60044.1 • All new voltage transformers must comply with Australian Standard AS60044.2; and • All new *meter*s must comply with Australian Standard 1284. When the exemption is extinguished the National Measurements *Act* will apply.		Type 1 - 6
5.79			Appropriate test certificates are to be kept by the equipment owner.	4.3	
5.80		Testing of metering equipment	The metering equipment purchased must be tested to the following class accuracy and with less than the following uncertainties: • Class 0.2 CT & VT 0.05%, 0.05Crad • Class 0.2 Wh *meter* 0.05/cosϕ% • Class 0.5 varh *meter* 0.2/sinϕ%	Table 3,	Type 1
5.51			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT/VT in laboratory 0.05%, 0.05Crad • *Meter* Wh in laboratory 0.05/cosϕ% • *Meter* Wh in field 0.1/cosϕ% • *Meter* varh in laboratory 0.2/sinϕ% • *Meter* varh in field 0.3/sinϕ%		Type 1

5.82			The maximum periods between sample testing are to be: • CT & VT 10 years • Burden tests When changes are made • Electronic *meter* 5 years • Induction *meter* 2.5 years		Type 1
5.83			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% Active 0.7% 0.5% 0.5% Overall accuracy at 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 0.7% 0.5% 0.5% reactive 1.4% 1.0% 1.0% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 0.5% n/a reactive n/a 1.0% n/a Overall accuracy zero power factor Energy Rated Load 10% 50% 100% reactive 1.4% 1.0% 1.0%	Table 4	Type 1

			The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component parts, that is, a + b + c, where: • a = the error of voltage transformer and wiring; • b = the error of the current transformer and wiring • c = the error of the *meter*. *energy data* for type 1 *metering installations* is usually based on watthour (*Active energy*). Where reactive *energy* is required the *metering installation* must also satisfy the requirements for varhour in this *Metrology Procedure*.		
5.84			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: Class 0.5 CT & VT 0.1%, 0.1% Crad Class 0.5 Wh *meter* 0.1/cosΦ % Class 1.0 varh *meter* 0.3/sinΦ %	Table 3	Type 2
5.85			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT/VT in laboratory 0.1%, 0.1 Crad • *Meter* Wh in laboratory 0.1/cosΦ % • *Meter* Wh in field 0.2/cosΦ % • *Meter* varh in laboratory +0.3/sinΦ % • *Meter* Wh in field +0.4/sinΦ %		Type 2
5.86			The maximum periods between sample testing are to be: CT & VT 10 years Burden tests When changes are made Electronic *meter* 5 years Induction *meter* 2.5 years		Type 2

5.87			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% Active 1.4% 1.0% 1.0% Overall accuracy at 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 1.4% 1.0% 1.0% reactive 2.8% 2.0% 2.0% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 1.0% n/a reactive n/a 2.0% n/a Overall accuracy zero power factor Energy Rated Load 10% 50% 100% reactive 2.8% 2.0% 2.0%	Table 5	Type 2

			The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component parts, that is, a + b + c, where: • a = the error of voltage transformer and wiring; • b = the error of the current transformer and wiring • c = the error of the *meter*.		
5.88			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: • Class 0.5 CT & VT 0.1% .01 Crad • Class 1.0 Wh *meter* 0.2/cosΦ % • Class 2.0 varh *meter* 0.4/sinΦ % • General Purpose *meter* 0.3/cosΦ %	Table 3	Type 3
5.89			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT/VT in laboratory ±0.1% • *Meter* Wh in laboratory +0.2/cosΦ % • *Meter* Wh in field +0.3/cosΦ % • *Meter* varh in laboratory +0.4/sinΦ % • *Meter* Wh in field +0.5/sinΦ %		Type 3
5.90			The maximum periods between sample testing are to be: • CT & VT 10 years • Burden tests When changes are made • CT connected electronic *meter* 5 years • CT connected induction *meter* 5 years • Whole current (direct connected) *meter* is to be tested in accordance with the *Meter* Providers asset management plan.		Type 3

5.91			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% Overall accuracy at 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% reactive 4.0% 3.0% 3.0% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active n/a 1.5% n/a reactive n/a 3.0% n/a Overall accuracy zero power factor Energy Rated Load 10% 50% 100% reactive 4.0% 3.0% 3.0% The above measurements are referenced to 25ºC	Table 6	Type 3

			Method of calculating the overall error is the vector sum of the errors of each component part, that is, A+B+C, where: • A = the error of voltage transformer and wiring; • B = the error of the current transformer and wiring • C = the error of the *meter*		
5.92			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: • Class 0.5 CT 0.1%, 0.5 Crad • Class 1.0 Wh *meter* 0.2/cosΦ % • General Purpose *meter* 0.3/cosΦ %	Table 3	Type 4
5.93			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • CT in laboratory 0.1% • CT in field 0.2% • *Meter* Wh in laboratory 0.2/cosΦ % • *Meter* Wh in field 0.3/cosΦ %	Table 3	Type 4
5.94			The maximum periods between sample tests are to be: • CT & VT 10 years • Burden tests When changes are made • CT connected electronic *meter* 5 years • CT connected induction *meter* 5 years • Whole current (direct connected) *meter* is to be tested in accordance with the *Meter* Providers asset management plan.		Type 4
5.95			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% *Active* 2.0% 1.5% 1.5%	Table 7	Type 4 - 6

			Overall accuracy 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active 1.5% 1.5% n/a The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component part, that is, A+B+C, where: • A = the error of voltage transformer and wiring; • B = the error of the current transformer and wiring • C = the error of the *meter*		
5.96			Testing of the components of the *metering installation* may be conducted in accordance with the asset management strategy that defines an alternative testing practice (ie other than time based) approved by the *Authority*, and with a test plan which has been registered with the *Authority*, to the same requirements as for new equipment where equipment is to be recycled for use in another site.		
5.97			If practicable, current transformer and voltage transformer tests are primary injection tests or other testing procedures as approved by the *Authority*.		
5.98			Other affected parties may witness the tests on request.		
5.99			The test results must be provided as soon as practicable to the requesting *Code* participant.		
5.100			All reference/calibrated equipment shall be tested to ensure full traceability to Australian national measurement standards through verifying authorities or directly referenced to the National Measurement Laboratory.		
5.101			The calculations of accuracy based on test results, are to include all reference standard errors.		
5.102			An “estimate of testing uncertainties” must be calculated in accordance with the ISO “Guide to the Expression of Uncertainty for Measurement”.		

5.103	Inspections of metering equipment		The testing and inspection requirements must be by an asset management strategy.		Type 1 - 6
5.104			A typical inspection might include: check the seals; compare the pulse counts; compare the direct readings of *meter*s, verify *meter* para*meter*s and physical connections, verify current transformer ratios by comparison.		
5.105		*Act*ions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Authority* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrange for the accuracy of the *metering installation* to be restored in a time frame agreed with the *Authority*.		
5.106			If a test or audit of a *metering installation* demonstrates an error of measurement of less than 1.5 times permitted by this schedule, no substitution of readings is required unless in Authorities reasonable opinion a particular party would be significantly affected if no substitution was made.		
5.107			If a *metering installation* test, inspection or audit demonstrates errors in excess of those prescribed and the time at which those errors arose is not known, the error is deemed to have occurred at a time half way between the time of the most recent test or inspection which demonstrated that the *metering installation*, or the *meter* family to which the *meter* of the *meter* installation belongs, complied with the relevant accuracy requirement and the time when the error was detected.		
5.108	Management, maintenance and auditing				
5.109		Installation and maintenance	The *Network Operator* must ensure that any metering equipment that they install is suitable for the range of operating conditions to which it will be exposed (e.g. temperature; impulse levels), and operates within the defined limits for that equipment.	3.5(3)(c)(1)	
5.110		Supporting information	Suitable drawings and supporting information, detailing the *metering installation*, must be available for maintenance and auditing purposes.	3.12(4)	
5.111		Security controls	Provide and maintain the security controls of a *metering installation*.	3.8	
5.112			The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls.	4.8(4)(a)	
5.113			The *Network Operator* must keep records of electronic access passwords secure.	4.8(5)(b)	
5.114			Energy data and passwords are confidential data and are to be treated as confidential information.	7.4(1)	
5.115			A *Registered Metering installation Provider* must be accredited by and registered with	6.9	

			Network Operator, and only for the type of work the *Registered Metering installation Provider* is qualified to provide.		
5.116			*registered metering installation providers*, who wish to apply for categories of *Registered Metering installation Provider* accreditation of *metering installation*, must be able to exhibit, to the reasonable satisfaction of the *Network Operator* the capabilities.	6.9	

6 Schedule 2 – Components of a Type 5 Metering Installation – Meter Provision

Ref.	Metering equipment components	Metering equipment characteristics	Requirement	*Metering Code* Clause or Table	Applicable *Metering installation* Type
6.1	Connection point	Metering Point	Electricity flowing through the connection point is to be greater than 50 but less than 300 MWh per annum.	Table 3	Type 5
6.2		*Metering installation*	No “check” *metering installation* required.	Table 1	Type 3 - 6
6.3			The revenue metering point is to be located as close as practicable to the connection point.	3.5(4)	Type 1 - 6
6.4			The *meter* is to be mounted on an appropriately constructed panel.	3.5	
6.5		Overall accuracy	Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy*.	Table 3 & 7	Type 4 - 6
6.6		Testing facilities	Suitable isolation facilities are to be provided to facilitate testing and calibration of the *metering installation*.	3.12(3)	Type 1 - 6
6.7	Instrument Transformers				
6.8		Current transformer	The accuracy of the current transformer is to be in accordance with class 0.5.	Table 3	Type 2 - 5
6.9			The current transformer core and secondary wiring associated with the revenue *meter* may not be used for other purposes.	3.12(b)	Type 1 - 5
6.10			New current transformers must meet the relevant requirements of AS 60044.1 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.12(2)	Type 1 - 5
6.11			Current transformers in service at the *Code* commencement date that do not comply with the accuracy requirements are acceptable providing the overall accuracy of the installation meets *Code* requirements for the applicable type *metering installation*.	3.14(3)	Type 1 - 5
6.12		Secondary wiring	Separate secondary windings should be provided for each *metering installation*.		Type 1 - 5
6.13			Secondary wiring must be by the most direct route and the number of terminations and	1.12(1f)	Type 1 - 5

			links must be kept to a minimum.		
6.14			• 2.5 mm² cable is required for current transformer secondary wiring. • 1.5 mm² cable is required for voltage transformer secondary wiring		Type 1 - 5
6.14			The incidence and magnitude of burden changes on any secondary winding supplying the *metering installation* must be kept to a minimum.	3.9(3)	
6.15		Performance	Energy data is required for all trading intervals within the time agreed with the relevant retailers at a level of availability of at least 99% per annum for instrument transformers	3.11(1)(a)	
6.16		Outages	If an outage or malfunction occurs to an instrument transformer, repairs must be made as soon as practicable.	4.7(2)	
6.17	Measurement element				
6.18		Design standard	*Meter*s must meet the relevant requirements of AS1284 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.1	
6.19		Design Standard	•*Meter*s in service at the *Code* commencement date whose accuracy does not meet *Code* requirements may remain in service for as long as the overall accuracy of the installation complies with the overall accuracy for a type of *metering installation*.	3.14	
6.20			*Meter*s must be capable of separately registering and recording flows in each direction where bi-directional *Active energy* flows.	3.16(1)(b)	
6.21		Accuracy	The accuracy of the Active element is to be class 1.0 for CT installation or general purpose	Table 3	Type 5
6.22		Visible display	To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2(1)	
6.23		Location	The revenue metering point is located as close as practicable to the connection point.	3.5(4)	
6.24		Security	The measurement element must be secure and associated links, circuits and information storage and processing systems must be secured by means of seals or other devices approved by the *Authority*.	3.8	
6.25		Storage	The measuring device must store Active *energy data* in a data logger. The data logger can be external or internal to the measuring element.	3.5(2)	Type 4 - 5
6.26					
6.27		Access to data	Access to the visible display is to be provided without unreasonable restriction.	3.2(1)	

6.28			Access to the electronic signal from the measurement element is secured. Relays or electronic buffers to prevent accidental or malicious damage to the *meter* must isolate interfaces to customer equipment.	3.23	
6.29			Access to the electronic signal for use in evolving technologies is to be discussed with the *Network Operator*.	3.4	
6.30			Alteration to the original stored data in a *meter* is not permitted except during on-site accuracy testing.	5.21(12)	
6.31		Outages	. If an outage or malfunction occurs to a measurement element or associated secondary wiring, repairs must be made as soon as practicable.	3.11	
6.32	Data logger				
6.33		Input connection	The data logger is to be electrically connected to the measurement element by secure means.		
6.34		Design standard	Any programmable settings available within a *metering installation*, data logger or any peripheral device, which may affect the resolution of displayed or stored data, must meet the relevant requirements of AS 1284 and must comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.10	
6.35		Location	. The data logger may be located within the same housing as the measurement element or in a separate housing.	1.3	
6.36			The data logger may be located at the same site as the measuring element or at a remote site.		
6.37		Security	The data logger is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Authority*.	3.8	
6.38		Processing of data	Data relating to the amount of Active passing through a connection point must be collated into trading intervals.	3.16(3)	
6.39		Time function	The data logger clock is to be referenced to Western Australian Standard Time.	3.21 Table 3	Type 1 - 5
6.40		Storage	The data logger is to have the capability of storing energy data for a period of at least 35 days.	3.16(c), 3.21(2)	Type 1 - 5
6.41			A metering database will be required to store *energy data* for a period of at least 35 days if it is to be used as a remote data logger.	4.9	
6.42		Access to data	Alteration to the original stored data in a data logger is not permitted except during on-site accuracy testing.	5.21(12)	

6.43		Performance	Energy data is required for all trading intervals a level of availability of at least 99% per annum from the data logger.		
6.44		Outages	If an outage or malfunction occurs to a data logger, repairs must be made as soon as practicable.	3.11(2)	
6.45	Communication link	Location	The electronic connection between the data logger and the telecommunications network boundary is classified as a communications link.	1.3	
6.46		Equipment	A communications link may consist of a metallic cable connecting to the telecommunications network and require isolation equipment, modem and associated connections	3.3(3)	
6.47			A communications link may include a radio, communications system, a microwave communications system or a satellite communications system or a combination of systems	3.3(3)	
6.48			A communications link may include a metering database.	3.3(3)	
6.49		Modem	Used to connect the *metering installation* to the telecommunications network at a data logger or metering database.		
6.50		Security	The communication link is to be secure and associated links, circuits and information storage and processing systems are to be secured by means of seals or other devices approved by the *Authority*.	3.8	
6.51		Access to data	The *metering installation* must be capable of local electronic access	4.18	Type 5
6.52			The data held in the *metering installation* is to be protected from direct or remote electronic access by suitable password and security controls.	4.8(3) (4)(a)	Type 1 - 5
6.53		Performance	Energy data is required for all trading intervals at a level of availability of at least 95% per annum from the communications link.	3.11(b)	Type 1 - 5
6.54		Outages	If an outage or malfunction occurs to a communications link, repairs must be made as soon as practicable in accordance the applicable service level agreement.	3.11(2)	Type 1 – 6
6.55	Testing and inspection				
6.56		Purchase of metering equipment	At present National Measurements Institute regulations exempts Utility *Meter*s from the National Measurements *Act*. Whilst the exemption is in place • All new purchased current transformers must comply with Australian Standard AS60044.1 • All new voltage transformers must comply with Australian Standard AS60044.2; and • All new *meter*s must comply with Australian Standard 1284.		Type 1 - 6

			When the exemption is extinguished the National Measurements *Act* will apply.		
6.57			Appropriate test certificates are to be kept by the equipment owner.	4.3	
6.58			The CT's purchased must be tested to the required class accuracy with less than ± 0.1 % uncertainty. The testing of the CT's in the *metering installation* is carried out as follows: • Maximum allowable level of testing uncertainty in the laboratory 0.1 %., 0.1 Crad • Maximum period between tests – 10 years.	Table 3	Type 5
6.59			The CT connected *meters* purchased must be tested to the required class accuracy with less than 0.2/cosϕ% uncertainty.		Type 5
6.60			The uncertainty associated with testing of the CT connected *meters* in the *metering installation* is carried out as follows: • Maximum allowable level of testing uncertainty in the laboratory 0.3/cosϕ% • Maximum allowable level of testing uncertainty in the field 0.3/cosϕ%. • Maximum period between tests – 7 years.		Type 5
6.61			The direct connected *meters* purchased must be tested to the required class accuracy with less than 0.3/cosϕ% uncertainty.		Type 5
6.61			The accuracy of the measurement element is to be in accordance with class 1.5 for General Purpose watthour *meters* as per AS1284 or in accordance with class 1.0 as per AS1284 or IEC1036 standards.		
6.62			If practicable, current transformer is primary injection tests or other testing procedures as approved by the *Authority*.		
6.63			Other affected parties may witness the tests on request.		
6.64			The test results must be provided as soon as practicable to the requesting *Code* participant.		
6.65			All reference/calibrated equipment shall be tested to ensure full traceability to Australian national measurement standards through verifying authorities or directly referenced to the National Measurement Laboratory.		
6.66			The calculations of accuracy based on test results, are to include all reference standard errors.		
6.67			An "estimate of testing uncertainties" must be calculated in accordance with the ISO "Guide to the Expression of Uncertainty for Measurement".		

6.68	Inspections of metering equipment		The testing and inspection requirements must be by an asset management strategy.		Type 1 - 6
6.69			A typical inspection might include: check the seals; compare the pulse counts; compare the direct readings of *meter*s, verify *meter* param*eter*s and physical connections, verify current transformer ratios by comparison.		
6.70		*Actions* in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Authority* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrange for the accuracy of the *metering installation* to be restored in a time frame agreed with the *Authority*.		
6.71			If a test or audit of a *metering installation* demonstrates an error of measurement of less than 1.5 times permitted by this schedule, no substitution of readings is required unless in Authorities reasonable opinion a particular party would be significantly affected if no substitution were made.		
6.72			If a *metering installation* test, inspection or audit demonstrates errors in excess of those prescribed and the time at which those errors arose is not known, the error is deemed to have occurred at a time half way between the time of the most recent test or inspection which demonstrated that the *metering installation*, or the *meter* family to which the *meter* of the *meter* installation belongs, complied with the relevant accuracy requirement and the time when the error was detected.		
6.73	Management, maintenance and auditing		The testing and inspection requirements must be by an asset management strategy.		Type 1 - 6
6.74		Installation and maintenance	The *Network Operator* must ensure that any metering equipment that they install is suitable for the range of operating conditions to which it will be exposed (e.g. temperature; impulse levels), and operates within the defined limits for that equipment.	3.5(3)(c)(1)	
6.75		Supporting information	Suitable drawings and supporting information, detailing the *metering installation*, must be available for maintenance and auditing purposes.	3.12(4)	
6.76		Security controls	Provide and maintain the security controls of a *metering installation*.	3.8	
6.77			The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls.	4.8(4)(a)	
6.78			The *Network Operator* must keep records of electronic access passwords secure.	4.8(5)(b)	
6.79			Energy data and passwords are confidential data and are to be treated as confidential information.	7.4(1)	
6.80			A *Registered Metering installation Provider* must be accredited by and registered with	6.9	

			Network Operator, and only for the type of work the *Registered Metering installation Provider* is qualified to provide.		
6.81			*Registered metering installation providers*, who wish to apply for categories of *Registered Metering installation Provider* accreditation of *metering installation*, must be able to exhibit, to the reasonable satisfaction of the *Network Operator* the capabilities.	6.9	

7 Schedule 3 – Components of a Type 6 Metering Installation – Meter Provision

Ref.	Metering equipment components	Metering equipment characteristics	Requirement	*Metering Code* Clause or Table	Applicable *Metering installation* Type
7.1	Connection point	Metering Point	Electricity flowing through the connection point is to be less than 50 MWh per annum.	Table 3	Type 6
7.2		*Metering installation*	No "check" *metering installation* required	Table 1	Type 3 - 6
7.3			The revenue metering point is to be located as close as practicable to the connection point.	3.5(4)	Type 1 - 6
7.4			The *meter* is to be mounted on an appropriately constructed panel	3.5	
7.5		Overall accuracy	Overall accuracy for a *metering installation* shall be no greater than 1.5% for *Active energy*	Table 3 & 7	Type 4 - 6
7.6		Testing facilities	Suitable isolation facilities are to be provided to facilitate testing and calibration of the *metering installation*.	3.12(3)	Type 1 - 6
7.7	Measurement element				
7.8		Design standard	*Meter*s must meet the relevant requirements of AS1284 and must also comply with any applicable specifications or guidelines (including any transitional arrangements) specified by the National Measurement Institute under the National Measurement *Act*.	3.1	
7.9		Design Standard	*Meter*s in service at the *Code* commencement date whose accuracy does not meet *Code* requirements may remain in service for as long as the overall accuracy of the installation complies with the overall accuracy for a type of *metering installation*.	3.14	
7.10		Accuracy	The accuracy of the *meter* class is to be general purpose	Table 3	Type 6
711		Visible display	To be provided on a device and to display as a minimum the accumulated total *Active energy* measured by that *metering installation*.	3.2(1)	
7.12		Location	The revenue metering point is located as close as practicable to the connection point.	3.5(4)	
7.13		Security	The measurement element must be secure and associated links, circuits and information storage and processing systems must be secured by means of seals or other devices	3.8	

			approved by the *Authority*.		
7.14		Access to data	Access to the visible display is to be provided without unreasonable restriction.	3.2(1)	
7.15			Access to the electronic signal from the measurement element is secured. Relays or electronic buffers to prevent accidental or malicious damage to the *meter* must isolate interfaces to customer equipment.	3.23	
7.16			Access to the electronic signal for use in evolving technologies is to be discussed with the *Network Operator*.	3.4	
7.17			Alteration to the original stored data in a *meter* is not permitted except during on-site accuracy testing.	5.21(12)	
7.18		Outages	If an outage or malfunction occurs to a measurement element or associated wiring, repairs must be made as soon as practicable.	3.11	
7.19	Testing and inspection				
7.20		Purchase of metering equipment	At present National Measurements Institute regulations exempts Utility *Meter*s from the National Measurements *Act*. Whilst the exemption is in place • All new *meter*s must comply with Australian Standard 1284. • When the exemption is extinguished the National Measurements *Act* will apply.	3.1	Type 1 - 6
7.21			Appropriate test certificates are to be kept by the equipment owner.	4.3	
7.22		Testing of metering equipment	The metering equipment purchased must be tested to the following class accuracy and with less than the following uncertainties: General purpose Wh *meter*, 0.2/cosϕ%		Type 6
7.23			The metering equipment purchased must be tested to the following class accuracy and with less that the following uncertainties: • General Purpose *meter* 0.3/cosΦ %	Table 3	Type 6
7.24			The uncertainties associated with testing of the components of the *metering installation* may be carried out as follows: • *Meter* Wh in laboratory 0.2/cosΦ % • *Meter* Wh in field 0.3/cosΦ %	Table 3	Type 6
7.25			The maximum periods between sample tests are to be: • Whole current (direct connected) *meter* is to be tested in accordance with the *Meter*		Type 6

			Providers asset management plan.		
7.26			Overall accuracy at unity power factor Energy Rated Load 10% 50% 100% *Active* 2.0% 1.5% 1.5% Overall accuracy 0.866 lagging power factor Energy Rated Load 10% 50% 100% Active 2.0% 1.5% 1.5% Overall accuracy 0.5 lagging power factor Energy Rated Load 10% 50% 100% Active 1.5% 1.5% n/a The above measurements are referenced to 25ºC Method of calculating the overall error is the vector sum of the errors of each component part, that is, A+B+C, where: • A = the error of voltage transformer and wiring; • B = the error of the current transformer and wiring • C = the error of the *meter*	Table 7	Type 4 - 6
7.27			Testing of the components of the *metering installation* may be conducted in accordance with the asset management strategy that defines an alternative testing practice (ie other than time based) approved by the *Authority*, and with a test plan which has been registered with the *Authority*, to the same requirements as for new equipment where equipment is to be recycled for use in another site.		
7.28			Other affected parties may witness the tests on request.		
7.29			The test results must be provided as soon as practicable to the requesting *Code* participant.		
7.30			All reference/calibrated equipment shall be tested to ensure full traceability to Australian national measurement standards through verifying authorities or directly referenced to the National Measurement Laboratory.		
7.31			The calculations of accuracy based on test results, are to include all reference standard		

			errors.		
7.32			An "estimate of testing uncertainties" must be calculated in accordance with the ISO "Guide to the Expression of Uncertainty for Measurement".		
7.33	Inspections of metering equipment		The testing and inspection requirements must be by an asset management strategy.		Type 1 - 6
7.34			A typical inspection might include: check the seals; compare the pulse counts; compare the direct readings of *meter*s, verify *meter* para*meter*s and physical connections, verify current transformer ratios by comparison.		
7.35		*Act*ions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Authority* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrange for the accuracy of the *metering installation* to be restored in a time frame agreed with the *Authority*.		
7.36			If a test or audit of a *metering installation* demonstrates an error of measurement of less than 1.5 times permitted by this schedule, no substitution of readings is required unless in Authorities reasonable opinion a particular party would be significantly affected if no substitution was made.		
7.37			If a *metering installation* test, inspection or audit demonstrates errors in excess of those prescribed and the time at which those errors arose is not known, the error is deemed to have occurred at a time half way between the time of the most recent test or inspection which demonstrated that the *metering installation*, or the *meter* family to which the *meter* of the *meter* installation belongs, complied with the relevant accuracy requirement and the time when the error was detected.		
7.38	Management, maintenance and auditing		The testing and inspection requirements must be by an asset management strategy.		Type 1 - 6
7.39		Installation and maintenance	The *Network Operator* must ensure that any metering equipment that they install is suitable for the range of operating conditions to which it will be exposed (e.g. temperature; impulse levels), and operates within the defined limits for that equipment.	3.5(3)(c)(1)	
7.40		Supporting information	Suitable drawings and supporting information, detailing the *metering installation*, must be available for maintenance and auditing purposes.	3.12(4)	
7.41		Security controls	Provide and maintain the security controls of a *metering installation*.	3.8	
7.42			The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls.	4.8(4)(a)	
7.43			The *Network Operator* must keep records of electronic access passwords secure.	4.8(5)(b)	

7.44			Energy data and passwords are confidential data and are to be treated as confidential information.	7.4(1)	
7.45			A *Registered Metering installation Provider* must be accredited by and registered with *Network Operator*, and only for the type of work the *Registered Metering installation Provider* is qualified to provide.	6.9	
7.46			*registered metering installation providers*, who wish to apply for categories of *Registered Metering installation Provider* accreditation of *metering installation*, must be able to exhibit, to the reasonable satisfaction of the *Network Operator* the capabilities.	6.9	

8 Schedule 4 – Components of a Type 1-5 Metering Installation – Energy Data Services

The components and characteristics and requirements of a *Metrology Procedure* for type 5 *metering installations* (*energy data services*) are as follows:

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.1	Metering database	Location	The metering *database* is located at a site remote from the site of the *meter* installation.	
8.2		Security	The metering *database* is to be secure and the associated links, circuits and information storage and processing systems are to be secured by means of locks, seals or other devices approved by The *Network Operator*.	4.8(4)
8.3			The metering *database* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, appropriate encryption and other electronic security controls, in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
8.4			Metering *database* passwords are confidential data and are to be treated as confidential information subject to Part 7.4 of the *Metering Code*.	7.4(1)
8.5		Processing and storage of data	The original energy readings must be stored in the metering *database*. Data relating to the amount of *Active energy* passing through a connection point must be collated and stored by data stream in half hourly trading intervals within the metering *database*. The *energy data* may be substituted in accordance with clause 3.3 or estimated in accordance with clause 3.4 of this *Metrology Procedure*.	4.1(1)(b)
8.6			Following a successful read, substitution or estimation, the metering *database* will store the *energy data* for a period of at least 13 months in a readily accessible online format and for a further period of five years and eleven months in archive that is accessible independently of the format in which the data is stored.	
8.7		Time function	The metering *database* clock must be referenced to Australian Western Standard TIME (AWST) and maintained within an absolute error of 20 seconds.	3.9(3)
8.8		Access	The format of the *energy data* must be in accordance with the electronic interface specification as nominated from time to time by the *Network Operator*.	
8.9			The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* and the *user* of the *connection point* with which	4.8(3), 4.8(4), 4.8(5)

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
			the *metering installation* is associated	
8.10			*Energy data* (either actual, substituted or estimated) is required by *Network Operator* by data stream for all trading intervals (that is, 48 intervals per 24 hour period) within the timeframe required for settlements as specified in procedures established by *Network Operator*.	Market Rules 8.7.1(b)
8.11			*Energy data* (either actual, substituted or estimated) is required by *Network Operator* by data stream for all trading intervals (that is, 48 intervals per 24 hour period) in accordance with performance standards established by *Network Operator*	3.16(3)
8.12		Outages	The *metering installation* database must permit collection of data within the timeframes specified in the relevant service level agreement at a level of availability of at least 99% per annum.	3.11(1)(a)
8.13			If an outage or malfunction occurs to a *metering installation database*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*	3.11(2)
8.14			A *Code Participant* who becomes aware of an outage or malfunction of a *metering installation* must advise the *Network Operator* as soon as practicable.	3.11(3)
8.15	*Metering installation* database	Security	The *metering installation database* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, appropriate encryption and other electronic security controls, in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
8.16			*Metering installation database* passwords are confidential data and are to be treated as confidential information subject to Part 7.4 of the *Metering Code*.	7.4(1)
8.17		Processing and storage of data	The *metering installation database* must store *energy data* for a period of at least 35 calendar days from the date and time of the last successful read.	3.16(1)(c)
8.18		Time function	The *metering installation database* clock must be referenced to Australian Western Standard TIME (AWST) and maintained within an absolute error of 20 seconds.	3.9(3)
8.19		Access to the *metering installation* database	The *metering installation database* must have electronic data transfer facilities to transfer data to the metering *database*. *{Note: 3.16(2) only requires a link for types1-4, in practice all interval capable meters will have some form of remote access.}*	
8.20			The format of the *energy data* must be in accordance with the electronic interface specification as nominated from time to time by the *Network Operator*.	

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.21			The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* and the *user* of the *connection point* with which the *metering installation* is associated	4.8(3), 4.8(4), 4.8(5)
8.22	Communications link	Location	(Comment provided for explanation only) The electronic connection between the metering *database* and the telecommunications network boundary is classified as a communications link.	
8.23			(Comment provided for explanation only) The electronic connection between the data logger and the metering *database* is classified as a communications link.	
8.24			(Comment provided for explanation only) A communications link may consist of a manual *meter* reading process and a metering *database*.	
8.25		Modem	(Comment provided for explanation only) A modem is used to connect the metering *database* to the telecommunications network.	
8.26		Remote acquisition of data	(Comment provided for explanation only) The *Network Operator* is responsible for the remote acquisition of the *energy data* from the *metering installation*	
8.27			Relevant *energy data* must be provided to *Network Operator* or its agent should a failure of the remote acquisition facility occur, and such an arrangement has been made by *Network Operator*	
8.30			Access to the metering *database* from a telecommunications network must be provided to facilitate the remote acquisition of data	
8.31		Security	The *communications link* is to be secure and the associated links, circuits and information storage and processing systems are to be secured by means of locks, seals or other devices approved by The *Network Operator*.	4.8(4)
8.32		Outages	The *communication link* must permit collection of data within the timeframes specified in the relevant service level agreement at a level of availability of at least 95% per annum.	3.11(1)(b)
8.33			If an outage or malfunction occurs to a *communication link*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*	3.11(2)

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
8.34			A *Code Participant* who becomes aware of an outage or malfunction of a *communication link* must advise the *Network Operator* as soon as practicable.	3.11(3)
8.35	Testing	Testing by *Network Operator*	The *Network Operator* must have unrestrained access to the *metering installation* for the purpose of testing the *metering installation* where *Network Operator* agrees to comply with reasonable security and safety requirements and has first given at least two business days' notice of its intention to access the *metering installation* for the purpose of testing the *metering installation*. The notice must include the name of the representative who will be conducting the test on behalf of the *Network Operator*, and the time when the test will commence and the expected time when the inspection will conclude	
8.36		Actions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Network Operator* and the affected *Code Participants* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrangements must be made for the accuracy of the *metering installation* to be restored in a time frame agreed with *Network Operator.*	
8.37		Errors	If a *metering installation* test, inspection or audit reveals errors in excess of those prescribed and the time at which those errors arose is not known and cannot be determined within a reasonable time or at reasonable cost, the error is deemed to have occurred half way between the time the error was detected and the time of the last test, inspection or audit that demonstrated that the *metering installation* complied with the specification or, if this is the first test, inspection or audit, the time the *metering installation* was commissioned.	
8.38			If the test, audit or inspection of the *metering installation* has revealed an error that is less then 1.5 times the maximum permitted, no substitution or estimation is necessary unless in the reasonable opinion of the *Network Operator* a *Code Participant* would be significantly affected if no substitution were made.	
8.39			If a test, audit or inspection reveals a discrepancy between the metering *database energy data* and the *metering installation energy data*, the *metering installation energy data* shall take precedence.	
8.40	Management, maintenance and auditing	Installation and maintenance	Only the *Network Operator*, in accordance with this Metrology Procedure, must carry out installation and maintenance of *metering installations*.	
8.41		Security controls	The energy data held in the *metering installation* is to be protected from direct local or remote electronic access by suitable password and security controls	
8.42			The *metering installation* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, and other electronic	4.8(4)

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
			security controls, in accordance with good electricity and IT industry practice.	
8.43			*Metering installation passwords* are confidential data and are to be treated as confidential information subject to Part 7.4 of the *Metering Code*.	7.4(1)
8.44			"Read-only" passwords must be allocated to *Code Participants*, Local Network Service Providers and *Network Operator*, except where separate "read-only" and" write" passwords are not available, in which case a password must be allocated to *Network Operator*, only.	
8.45			The *Network Operator* is responsible for maintaining the *metering installation* and metering *database* passwords.	

9 Schedule 5 – Components of a Type 6 Metering Installation – Energy Data Services

The components and characteristics and requirements of a *Metrology Procedure* for type 6 *metering installations* (*energy data services*) are as follows:

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
9.1	Metering database	Location	The metering *database* is located at a site remote from the site of the *meter* installation.	
9.2		Security	The metering *database* is to be secure and the associated links, circuits and information storage and processing systems are to be secured by means of locks, seals or other devices approved by The *Network Operator*.	4.8(4)
9.3			The metering *database* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, appropriate encryption and other electronic security controls, in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
9.4			Metering *database* passwords are confidential data and are to be treated as confidential information subject to Part 7.4 of the *Metering Code*.	7.4(1)
9.5		Processing and storage of data	The original energy readings must be stored in the metering *database*. Data relating to the amount of *Active energy* passing through a connection point must be collated and stored by data stream within the metering *database*. The *energy data* may be substituted in accordance with clause 3.3 or estimated in accordance with clause 3.4 of this *Metrology Procedure*.	4.1(1)(b)
9.6			Following a successful read, substitution or estimation, the metering *database* will store the *energy data* for a period of at least 13 months in a readily accessible online format and for a further period of five years and eleven months in archive that is accessible independently of the format in which the data is stored.	
9.7		Access	The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* and the *user* of the *connection point* with which the *metering installation* is associated	4.8(3), 4.8(4), 4.8(5)
9.8		Outages	If an outage or malfunction occurs to a metering *database*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*	3.11(2)

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
9.9			A *Code Participant* who becomes aware of an outage or malfunction of a *metering installation* must advise the *Network Operator* as soon as practicable.	3.11(3)
9.10	Testing	Testing by *Network Operator*	The *Network Operator* must have unrestrained access to the *metering installation* for the purpose of testing the *metering installation* where *Network Operator* agrees to comply with reasonable security and safety requirements and has first given at least two business days' notice of its intention to access the *metering installation* for the purpose of testing the *metering installation*. The notice must include the name of the representative who will be conducting the test on behalf of the *Network Operator*, and the time when the test will commence and the expected time when the inspection will conclude.	
9.11		Actions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Network Operator* and the affected *Code Participants* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrangements must be made for the accuracy of the *metering installation* to be restored in a time frame agreed by the *Network Operator.*	
9.12		Errors	If a *metering installation* test, inspection or audit reveals errors in excess of those prescribed and the time at which those errors arose is not known and cannot be determined within a reasonable time or at reasonable cost, the error is deemed to have occurred half way between the time the error was detected and the time of the last test, inspection or audit that demonstrated that the *metering installation* complied with the specification or, if this is the first test, inspection or audit, the time the *metering installation* was commissioned.	
9.13			If the test, audit or inspection of the *metering installation* has revealed an error that is less then 1.5 times the maximum permitted, no substitution or estimation is necessary unless in the reasonable opinion of the *Network Operator* a *Code Participant* would be significantly affected if no substitution were made.	
9.14			If a test, audit or inspection reveals a discrepancy between the metering *database energy data* and the *metering installation energy data*, the *metering installation energy data* shall take precedence.	
9.15	Management, maintenance and auditing	Installation and maintenance	Only the *Network Operator*, in accordance with this Metrology Procedure, must carry out installation and maintenance of *metering installations*.	
9.16		Security controls	The *energy data* held in the *metering installation* is to be protected from tampering by suitable security controls such as seals, in accordance with good electricity industry practice.	

10 Schedule 6 – Components of a Type 7 Metering Installation – Energy Data Services

The components and characteristics and requirements of a *Metrology Procedure* for type 7 *metering installations* (energy data services) are as follows:

Type 7 *metering installation* are associated with un-metered loads, as defined in article 3.9(2) of the *Metering Code*, and it is therefore necessary to define the means by which the *energy data* deemed to flow in the power conductor is determined and validated

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
10.1	Metering database	Location	The metering *database* is located at a site remote from the site of the *meter* installation.	
10.2		Security	The metering *database* is to be secure and the associated links, circuits and information storage and processing systems are to be secured by means of locks, seals or other devices approved by The *Network Operator*.	4.8(4)
10.3			The metering *database* is to be secure and the associated programs and data are to be secured from unauthorised local and remote by means of passwords, appropriate encryption and other electronic security controls, in accordance with good electricity and IT industry practice.	4.1(2), 4.8(4)
10.4			Metering *database* passwords are confidential data and are to be treated as confidential information subject to Part 7.4 of the *Metering Code*.	7.4(1)
10.5		Standing Data	The load tables, inventory tables and On/Off tables must be stored in the metering *database*.	A2.4
10.6		Processing and storage of data	Data relating to the amount of *Active energy* consumed by the unmetered load must be calculated, validated and substituted where required and stored within the metering *database* in accordance with articles A2.9 and A3.6 of the WA *Metering Code* 2005. *{Note: Guidance note (d) for 6.8(e) requires interval data. However this is required in support of calculation of the Notional Wholesale Meter as required by 3.16(4). The calculation of this is no longer a Network Operator responsibility (version 2.3 of the Market Rules, Chapter 11, definition of Notional Wholesale Meter “A notional interval meter quantity associated with a Market Customer’s aggregate consumption not metered by Trading Interval. This value will be an estimate produced by the IMO”).* *Hence only requirement for Type 7 data is for retailer billing. Current practice and systems utilize only daily data so the Metrology Procedures will not require interval data to be calculated but will not rule out its inclusion at some future point in time.}*	

Ref.	Energy data services components	Energy data services characteristics	Requirement	Clause in *Code*
10.7			The metering *database* must store *energy data* and the data used in the calculation of the *energy data*, such as the load tables, inventory tables and on/off tables, for a period of at least 13 months on line in accessible format and for a further period of 5 years and 11 months in archive that is accessible independently of the format in which the data is stored.	4.9
10.8		Access	The only persons entitled to have either direct or remote access to the *energy data* from a *metering installation* are the *Network Operator* and the *user* of the *connection point* with which the *metering installation* is associated	4.8(3), 4.8(4), 4.8(5)
10.9		Outages	If an outage or malfunction occurs to a metering *database*, repairs must be made as soon as practicable, and in any event within the period specified within the relevant *service level agreement*	3.11(2)
10.10	Testing	Actions in event of non-compliance	If the accuracy of the *metering installation* does not comply with the requirements of the *Code*, the *Network Operator* and the affected *Code Participants* must be advised as soon as practicable of the errors detected and the possible duration of the existence of errors, and arrangements must be made for the accuracy of the *metering installation* to be restored in a time frame agreed by the *Network Operator.*	
10.11		Errors	If a *metering installation* test, inspection or audit reveals errors in excess of those prescribed and the time at which those errors arose is not known and cannot be determined within a reasonable time or at reasonable cost, the error is deemed to have occurred half way between the time the error was detected and the time of the last test, inspection or audit that demonstrated that the *metering installation* complied with the specification or, if this is the first test, inspection or audit, the time the *metering installation* was commissioned.	
10.11			If the test, audit or inspection of the *metering installation* has revealed an error that is less then 1.5 times the maximum permitted, no substitution or estimation is necessary unless in the reasonable opinion of the *Network Operator* a *Code Participant* would be significantly affected if no substitution were made.	

11 Schedule 7 – Metering Installation Types 1-5 – Validation

11.1 Requirement to Validate

11.1.1 The energy data from *metering installations* of types 1-5 is required to be validated, in accordance with clause 3.4.1 of this Metrology Procedure.

11.2 Validation of energy data from Types 1-5 Metering Installations with Check Metering

11.2.1 The following checks apply to *energy data* from all *metering installations* of types 1-5 which have full *check* metering

a) The energy data must agree with the check *meter* reading to within the uncertainty limits of both *meter*s. i.e.

$$\frac{|R - C'|}{\left(\frac{R + C'}{2}\right)} \times 100 \leq |\Delta RC|$$

Where

|x|	means the absolute value of a quantity, *x*
R	is the *revenue meter* reading for the data stream, expressed in *energy units*
C'	is the associated *check meter* reading, expressed in *energy units*, and adjusted for known losses or systemic errors such as transformer losses
ΔRC	is the maximum discrepancy between the revenue and check *meter* expressed as a percentage and with a maximum value of 1%

{e.g. Meter A has a reading of 107.5 and the associated check meter reads 106. An analysis of historical data, systemic errors and the known uncertainties for the meters shows that the maximum acceptable difference is 0.9%. (107.5-106)/107.5 ×100 = 1.40% which is greater than the maximum allowable value so the reading will fail validation.

However, if we know that there is a transformer loss for the Check meter of 2% then we need to first determine an adjusted check meter reading. This would be 106/0.98 = 108.1. In this case (108.1-107.5)/107.5 ×100 = 0.6% which is within the tolerance allowed and the reading would pass validation.}

b) Where the energy data is associated with a market generator then it must be validated against SCADA data.

$$\frac{|R - S'|}{\left(\frac{R + S'}{2}\right)} \times 100 \leq |\Delta RS|$$

Where

|x|	means the absolute value of a quantity, *x*

R is the *revenue meter* reading for the data stream, expressed in *energy units*

S' is the associated *check meter* reading, converted to *energy units*, and adjusted for known losses or systemic errors such as transformer losses

ΔRS is the maximum discrepancy between the revenue and check *meter* expressed as a percentage.

c) The value must be less than the registered maximum value of Wh, Varh or VAh for the *metering installation* data stream.

d) The *Network Operator* and user will agree to either:

1 Check the metered value is greater than the registered minimum value for the *metering installation*, or

2 Check that the number of intervals with zero data is less than a specified number.

e) If an interval has a null value then the reading for that interval will be rejected.

f) If the *meter* has registered significant *meter* alarms over the period since the last successful read, the energy data will be rejected. Significant alarms include, but need not be limited to,:

1 Power failure,

2 VT or phase failure

3 Pulse overflow

4 CRC error

5 Time tolerance

g) The sum of the *interval data* readings must agree with the accumulated total for the *meter*. I.e.

$$\frac{\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|}{\left(\dfrac{\sum_{i=1}^{n} R_i + A'}{2}\right)} \times 100 \leq |\Delta RA|$$

Where,

|x| means the absolute value of a quantity, *x*

R_i is the data stream reading for interval *i,* expressed in *energy units.*

n is the total number of intervals in the period

A' is the reading from the associated accumulated energy registers, adjusted for any known systemic error

ΔRA is the maximum discrepancy between the revenue and check *meter* expressed as a percentage

11.3 Validation of energy data from Types 1-5 Metering Installations with Partial Check Metering

11.3.1 The following checks apply to *energy data* from all *metering installations* of types 1-5 which have partial *check* metering

a) The energy data must agree with the check *meter* reading to within the uncertainty limits of both *meter*s. i.e.

$$\frac{|R - C'|}{\left(\frac{R + C'}{2}\right)} \times 100 \le |\Delta RC|$$

Where

|x|	means the absolute value of a quantity, *x*
R	is the revenue *meter* data stream reading, expressed in *energy units*
C'	is the associated *check meter* reading, expressed in *energy units*, and adjusted for known losses or systemic errors such as transformer losses
ΔRC	is the maximum discrepancy between the revenue and check *meter* expressed as a percentage and with a maximum value of 1%

{e.g. Meter A has a reading of 107.5 and the associated check meter reads 106. An analysis of historical data, systemic errors and the known uncertainties for the meters shows that the maximum acceptable difference is 0.9%. (107.5-106)/107.5 ×100 = 1.40% which is greater than the maximum allowable value so the reading will fail validation.

However, if we know that there is a transformer loss for the Check meter of 2% then we need to first determine an adjusted check meter reading. This would be 106/0.98 = 108.1. In this case (108.1-107.5)/107.5 ×100 = 0.6% which is within the tolerance allowed and the reading would pass validation.}

b) Where the energy data is associated with a market generator then it must be validated against SCADA data.

$$\frac{|R - S'|}{\left(\frac{R + S'}{2}\right)} \times 100 \le |\Delta RS|$$

Where

|x|	means the absolute value of a quantity, *x*
R	is the *revenue meter* reading for the data stream, expressed in *energy units*
S'	is the associated *check meter* reading, converted to *energy units*, and adjusted for known losses or systemic errors such as transformer losses
ΔRS	is the maximum discrepancy between the revenue and check *meter* expressed as a percentage.

c) The value must be less than the registered maximum value of Wh, Varh or VAh for the *metering installation*.

d) The *Network Operator* and user will agree to either:

3 Check the metered value is greater than the registered minimum value for the *metering installation*, or

4 Check that the number of intervals with zero data is less than a specified number.

g) If an interval has a null value then the reading for that interval will be rejected.

h) If the *meter* has registered significant *meter* alarms over the period since the last successful read, the energy data will be rejected. Significant alarms include, but need not be limited to,:

1 Power failure,

2 VT or phase failure

3 Pulse overflow

4 CRC error

5 Time tolerance

g) The sum of the interval data readings must agree with the accumulated total for the *meter*. I.e.

$$\frac{\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|}{\left(\dfrac{\sum_{i=1}^{n} R_i + A'}{2}\right)} \times 100 \leq |\Delta RA|$$

Where,

|x| means the absolute value of a quantity, *x*

R_i is the data stream reading for interval *i*

n is the total number of intervals in the period

A’ is the reading from the associated accumulated energy registers, adjusted for any known systemic error

ΔRA is the maximum discrepancy between the revenue and check *meter* expressed as a percentage

11.4 Validation of energy data from Types 1-5 Metering Installations without Check Metering

11.4.1 The following checks apply to *energy data* from all *metering installations* of types 1-5 which have full *check* metering

a) The value must be less than the registered maximum value of Wh, Varh or VAh for the *metering installation*.

b) The *Network Operator* and user will agree to either:

1 Check the metered value is greater than the registered minimum value for the *metering installation*, or

2 Check that the number of intervals with zero data is less than a specified number.

c) If an interval has a null value then the reading for that interval will be rejected.

d) If the *meter* has registered significant *meter* alarms over the period since the last successful read, the energy data will be rejected. Significant alarms include, but need not be limited to,:

1 Power failure,

2 VT or phase failure

3 Pulse overflow

4 CRC error

5 Time tolerance

e) The sum of the interval data readings must agree with the accumulated total for the *meter*. I.e.

$$\frac{\left|\left(\sum_{i=1}^{n} R_i\right) - A'\right|}{\left(\dfrac{\sum_{i=1}^{n} R_i + A'}{2}\right)} \times 100 \leq |\Delta RA|$$

Where,

|x| means the absolute value of a quantity, *x*

R_i is the data stream reading for interval *i*

n is the total number of intervals in the period

A' is the reading from the associated accumulated energy registers, adjusted for any known systemic error

ΔRA is the maximum discrepancy between the revenue and check *meter* expressed as a percentage

12 Schedule 8 – Metering Installation Types 1-5 – Accumulation, Substitution and Estimation

12.1 Requirement to Produce Substituted or Estimated Energy Data

{Note – substitution generally occurs in response to a failure or problem with the metering installation or in response to data quality issues whereas estimation generally occurs when there is no physical or data problem but it has not been possible to take a reading for any reason.}

12.1.1 In accordance with clause 3.4.6 of this *Metrology Procedure*, *energy data* for a type 1-5 *metering installation* may be required to be substituted or estimated.

12.2 Requirement to Accumulate Energy Data to Trading Intervals

12.2.1 Where *energy data* is recorded in fifteen-minute intervals this must be accumulated to half-hourly values to coincide with the *trading interval.*

12.3 *Network Operator* Obligations

12.3.1 When the *energy data* is required to be substituted or estimated the *Network Operator* may use Substitution Types 11, 12, 13, 14, 15, 16, 17 and 18 for *Metering installations* of Types 1-4 and Substitution Types 51, 52, 53, 54, 55 and 56 for *Metering installations* of Type 5, all substitution types as defined in clause 12.4 of this Schedule 8.

12.3.2 The *Network Operator* must not perform substitutions or estimations for generating plant without prior consultation with the generator unless reliable check metering is available.

12.3.3 The *Network Operator* must not perform substitution of type 16 without the prior agreement of the affected parties.

12.3.4 The *Network Operator* will notify affected *Code Participant*s where substituted *energy data* is used via the status flag in the data file format.

12.3.5 Where one or more of the readings making up the interval data in accordance with 3.3.15 has failed validation and been substituted, this will be reflected in the status of the interval data reported under 12.3.4 and the status reported will reflect the most serious of the statuses associated with the constituent data.

{Note. Consider where data is collected in 15 minute intervals and aggregated to half hour periods. If one period had a warning status but the data was manually approved while the other 15 minute period failed and was substituted, the entire trading interval would be marked as a substitute.}

12.3.6 The *Network Operator* must ensure that for all Substitution Types, substituted *energy data* is based on an actual *meter* reading, and is not based on *energy data* that has previously been estimated or substituted.

12.3.7 Where a substitution type requires the use of historical data, the data source for historical data shall be data stream specific rather than *meter* specific.

{I.e. if a meter is swapped out the process will look at the history for the same data stream for the previous meter not just the limited data set available that is associated with the replacement meter.}

12.4 Accumulation of data to trading intervals

12.4.1 The formulae to use for converting fifteen-minute interval readings to half-hourly interval readings are listed in the following table:

Variable	Formula
HH Consumption	HH Consumption at interval $_{i+1}$ = sum (Consumption at QH interval $_{i}$, Consumption at QH interval $_{i+1}$) { I.e. Sum the reading values (kWh) of the two adjacent QH intervals to form the HH Consumption for the HH interval. For example, QH Consumption @ 00:15 = 20 kWh QH Consumption @ 00:30 = 50 kWh then HH Consumption @ 00:30 = 70 kWh}
HH Demand	HH Demand can be determined when data for HH Consumption is present HH Demand in kW at interval $_{i+1}$ = HH Consumption in kWh at interval $_{i+1}$ x $\frac{\text{Number of Intervals Per Day}}{\text{48 HH Intervals Per Day}}$ Where Number of Intervals Per Day = 48 HH intervals per day
HH Reactive Energy	HH Reactive Energy at interval $_{i+1}$ = sum (Reactive Energy at QH interval $_{i}$, Reactive Energy at QH interval $_{i+1}$) {I.e. Sum the reading values (kVArh) of the two adjacent QH intervals to form the HH Reactive Energy for the HH interval. For example , QH Reactive Energy @ 00:15 = 20 kVAh QH Reactive Energy @ 00:30 = 50 kVAh then

Variable	Formula
	HH Consumption @ 00:30 = 70 kVAh}
HH Apparent Energy	HH Apparent Energy at interval $_{i+1}$ can only be determined when data for HH Consumption and HH Reactive Energy are present. HH Apparent Energy in kVAh at interval $_{i+1}$ $= \sqrt{\text{HH Consumption}^2 + \text{HH Reactive Energy}^2}$ The units of Consumption = kWh The units of Reactive Energy = kVArh
Power Factor	Power Factor can only be determined when data for HH Consumption and HH Apparent Energy are present. Power Factor = $\dfrac{\text{HH Consumption in kWh}}{\text{HH Apparent Energy in kVAh}}$ The Power Factor should be between 0 and 1 inclusive.

12.5 Substitution and Estimation Types for Metering Installation Types 1-4

12.5.1 Substitution Method 11

Interval energy data obtained from another *meter* at the same measurement point for the same interval data periods as that being substituted for may be used for substitution purposes, e.g. installations where revenue and check *meter*s are installed.

Method 11 substitutions also include the use of data from similar *meter*s where the load profile of the second *meter* is a good match to the load profile of the *meter* for which substitutions are being made, e.g. where *meter*s are installed on each end of a transmission line where the difference due to line losses can be accurately determined; where *meter*s are installed on parallel feeders where supply is 'to' and 'from' common buses and line impedances are similar.

12.5.2 Substitution Method 12

Data values may be calculated for an unknown feed to a node based on the other known energy flows to or from that node.

{Note: For example if sub meters are available then a value could be determined by summing the readings from the submeters.}

12.5.3 Substitution Method 13

Data from an energy management system or SCADA data may be used for substitution purposes, where the data originates from a similar measurement point as the *meter* for which substitutions are being made.

Data from an energy management system or SCADA data may be data which is inferior in accuracy or resolution and which is in a dissimilar format to the energy data, (e.g. 30 Min. demand values). It may be necessary to adjust the data in both magnitude and form in order that the substitution is of an acceptable quality.

12.5.4 Substitution Method 14

Where data substitution methods 11, 12, and 13 cannot be carried out, then the *Network Operator* may substitute for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the table below.

METHOD 14	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
Monday	Monday ♦♦
Tuesday	Tuesday ♦♦ Wednesday♦♦ Thursday ♦♦ Wednesday ♦ Thursday ♦
Wednesday	Wednesday ♦♦ Tuesday ♦ Thursday ♦♦ Thursday ♦ Tuesday ♦♦
Thursday	Thursday ♦♦ Wednesday ♦ Tuesday ♦ Wednesday ♦♦ Tuesday ♦♦
Friday	Friday ♦♦
Saturday	Saturday ♦♦
Sunday	Sunday ♦♦
Substitutions for 'Like Day' to be as detailed above, unless: 1) If no readings are available on the first listed day, then the next listed preferred day is to be used. 2) The substitution day was a public holiday, in which case the most recent Sunday is to be used. 3) The substitution day was not a public holiday and the 'Like Day' is a public holiday, in which case the substitution 'Like Day' to be used must be the most recent business day. ♦♦ Occurring in the week preceding that in which the substitution day occurs. ♦ Occurring in the same week as the substitution day	

12.5.5 Substitution Method 15

Where data substitution methods 11, 12, and 13 cannot be carried out, then the *Network Operator* may substitute for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the Table below.

METHOD 15
The intervals to be substituted will be plugged using an average of each interval from the proceeding 4 weeks, or part thereof. This averaging technique may be applied in the following ways: 1) where the averaged intervals are simply 'plugged' into the intervals requiring substitution. 2) where the averaged intervals are used to provide the profile for the ones to be 'plugged' to a predetermined number of pulses for the total substitution period. However if data is required to be substituted for a public holiday then the most recent available Sunday will be used.

12.5.6 Substitution Method 16

(a) Where data substitution is required for any period greater than 7 days, consideration, consultation and agreement must take place between the affected parties to resolve any abnormal equivalent days that may be applicable.

(b) Method 16 substitutions are:

i. data substitutions of any format for periods greater than 7 days that are based on an agreement between all the affected parties;

ii. changes to existing substitutions for any period that are carried out where the affected parties have directed that as a result of site or customer specific information, the original substitutions are in error.

12.5.7 Substitution Method 17

Data substitutions for periods up to, but not exceeding 2 hours, may be carried out by simple linear interpolation.

12.5.8 Substitution Method 18

This substitution method covers the situation where an alternate method of substitution has been agreed with the *Code Participant*, the applicable user and the *Network Operator*. This may be a globally applied method or a site specific method where an adjusted profile is used to take into account local conditions which affect consumption (e.g. local holiday or customer shutdown), or where alternate data may be able to be used for quality checks and minor adjustments of an estimated profile such as using *meter* register data.

12.6 Substitution and Estimation Types for Metering Installation Type 5

12.6.1 Substitution Method 51

This method is known as the Previous Years Method. Where data substitution methods 11, 12, and 13 cannot be carried out, then the *Network Operator* may substitute for the missing data using the “Nearest Equivalent Day” or “Like Day” method, as detailed in the Table below.

METHOD 51	
Substitution Day	**“Nearest Equivalent Day” or “Like Day” (in order of availability)**
Monday	Monday ♦♦ Monday ♦
Tuesday	Tuesday ♦♦ Wednesday♦♦ Tuesday ♦ Wednesday ♦
Wednesday	Wednesday ♦♦ Tuesday ♦♦ Thursday ♦♦ Wednesday ♦ Thursday ♦ Tuesday ♦
Thursday	Thursday ♦♦ Wednesday ♦♦ Tuesday ♦♦ Thursday ♦ Wednesday ♦ Tuesday ♦
Friday	Friday ♦♦ Friday ♦
Saturday	Saturday ♦♦ Saturday ♦
Sunday	Sunday ♦♦ Sunday ♦
Substitutions for ‘Like Day’ to be as detailed above, unless: If no readings are available on the first listed day, then the next listed preferred day is to be used. 1 The substitution day was a public holiday, in which case the most recent Sunday is to be	

METHOD 51	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
used. 2 The substitution day was not a public holiday and the 'Like Day' is a public holiday, in which case the substitution 'Like Day' to be used must be the most recent business day. ♦♦ Occurring in the same week as the substitution day in the previous year. ♦ Occurring in the week preceding that in which the substitution day occurs in the previous year.	

12.6.2 Substitution Method 52

This method is known as the Previous *Meter* Reading Method. Where data substitution methods 11, 12, and 13 cannot be carried out, then the *Network Operator* may substitute for the missing data using the "Nearest Equivalent Day" or "Like Day" method, as detailed in the Table below.

METHOD 51	
Substitution Day	**"Nearest Equivalent Day" or "Like Day" (in order of availability)**
Monday	Monday ♦♦ Monday ♦
Tuesday	Tuesday ♦♦ Wednesday♦♦ Tuesday ♦ Wednesday ♦
Wednesday	Wednesday ♦♦ Tuesday ♦♦ Thursday ♦♦ Wednesday ♦ Thursday ♦ Tuesday ♦
Thursday	Thursday ♦♦ Wednesday ♦♦ Tuesday ♦♦ Thursday ♦ Wednesday ♦ Tuesday ♦
Friday	Friday ♦♦ Friday ♦
Saturday	Saturday ♦♦ Saturday ♦
Sunday	Sunday ♦♦ Sunday ♦
Substitutions for 'Like Day' to be as detailed above, unless: If no readings are available on the first listed day, then the next listed preferred day is to be used. 1 The substitution day was a public holiday, in which case the most recent Sunday is to be used. 2 The substitution day was not a public holiday and the 'Like Day' is a public holiday, in which case the substitution 'Like Day'to be used must be the most recent business day. ♦♦ Occurring in the last whole week of the previous *meter* reading period. ♦ Occurring in the week preceding that in which the substitution day occurs in the previous year.	

12.6.3 Substitution Method 53

(a) Where data substitution is required for any period greater than 7 days, consideration, consultation and agreement must take place between the affected parties to resolve any abnormal equivalent days that may be applicable.

(b) Method 53 substitutions are:

i. data substitutions of any format for periods greater than 7 days that are based on an agreement between all the affected parties;

ii. changes to existing substitutions for any period that are carried out where the affected parties have directed that as a result of site or customer specific information, the original substitutions are in error.

12.6.4 Substitution Method 54

Data substitutions for periods up to, but not exceeding 2 hours, may be carried out by simple linear interpolation.

12.6.5 Substitution Method 55

This substitution method covers the situation where an alternate method of substitution has been agreed with the *Code Participant*, the applicable user and the *Network Operator*. This may be a globally applied method or a site specific method where an adjusted profile is used to take into account local conditions which affect consumption (e.g. local holiday or customer shutdown), or where alternate data may be able to be used for quality checks and minor adjustments of an estimated profile such as using *meter* register data.

12.6.6 Substitution Method 56

This substitution method covers the situation where a substitution for interval energy data is required for a period prior to the first *meter* read. The data substitution must be done by a method agreed to by the *Network Operator* and the affected *Code Participant*.

13 Schedule 9 – Metering Installation Type 6 – Validation, Substitution and Estimation

13.1 Requirement to Validate Meter Readings

13.1.1 *Actual meter* readings will be required to be validated in accordance with clause 3.3.1 of this *Metrology Procedure*. The validation rules that may be applied to the *energy data* read from the *meter* of a type 6 *metering installation* are:

a) *Meter* read value is numeric, and

b) *Meter* read value is greater than or equal to the minimum value specified for that *meter*; and

c) *Meter* read value is less than or equal to the maximum value specified for that *meter*; and

d) *Meter* read date > previous *meter* read date; and

e) *Meter* read value is not missing (null) for any type 6 *meter*; and

f) Dial capacity, rollover and decimal point check.

{These checks mainly apply to older styles of mechanical *meter*s. For example:

- A dial capacity check means ensuring that if a *meter* dial has 5 digits then the maximum value recorded against that dial should be 99999 – a larger number should be flagged.
- A roll over check is required where upon successive reads a *meter* is showing a lower reading. For example consider a hypothetical mechanical *meter* with four digits. If on the last reading the value was 9995 and on the next reading it is 0010 then the dial is deemed to have "rolled over". The correct interpretation is that consumption is 10 + 10000 – 9995, or 15, units. On the other hand if the last reading was 0010 and this reading is 0009 then something is wrong since it is highly unlikely that the connection point consumed 9999 units since it was last read. It is more likely that the a reading was wrong (perhaps the last two digits were swapped around when it was recorded) or the *meter* is faulty.
- A decimal point check means checking that the reading has the correct number of digits after the decimal point for the dial. For example if a dial has 4 digits and the last digit denotes tenths of a unit then the reading should be in the range 000.0 to 999.9. If the reading is recorded as 12.34 then it needs to be flagged up and checked –(e.g. should it really be 123.4).

}

13.2 Requirement to Produce Substituted or Estimated Energy Data

{Note – substitution generally occurs in response to a failure or problem with the metering installation or in response to data quality issues whereas estimation generally occurs when there is no physical or data problem but it has not been possible to take a reading for any reason.}

13.2.1 In accordance with clause 3.4.6 of this *Metrology Procedure*, *energy data* for a type 6 *metering installation* may be required to be substituted or estimated.

13.3 *Network Operator* Obligations

13.3.1 When the *energy data* is required to be substituted or estimated the *Network Operator* may use Substitution Types 61, 62, 63, 64 or 65, as defined in clause 13.4 of this Schedule 9.

13.3.2 The *Network Operator* will notify affected *Code Participants* where substituted *energy data* is used via the status flag in the data file format.

13.3.3 The *Network Operator* must ensure that for all Substitution Types, substituted *energy data* is based on an actual *meter* reading, and is not based on *energy data* that has previously been estimated or substituted.

13.3.4 Where a substitution type requires the use of historical data, the data source for historical data shall be data stream specific rather than *meter* specific.

{I.e. if a meter is swapped out the process will look at the history for the same data stream for the previous meter not just the limited data set available that is associated with the replacement meter.}

13.4 Substitution and Estimation Types

13.4.1 Substitution/Estimation Type 61 – Previous Year Method

a) Value = Average daily consumption from same, or similar, *meter* read period last year × Number of days required to be substituted

13.4.2 Substitution/Estimation Type 62 – Previous *Meter* Reading Method

a) Value = Average daily consumption from previous *meter* read period × Number of days required to be substituted

b) Where the scheduled *meter* reading frequency is less frequent than monthly, Substitution Type 62 is to be used only when the consumption from the same, or similar, *meter* read period last year is not available.

13.4.3 Substitution/Estimation Type 63 – Customer Class Method

a) Value = Average daily consumption for this same customer class with the same type of usage × Number of days required to be substituted

b) Substitution Type 63 is to be used only when the consumption from the same, or similar, *meter* read period last year and the consumption from the previous *meter* read period are not available.

c) Customer classes for Substitution Type 63 are

ii. Residential,

iii. Non-Residential,

iv. Farm, and

v. Public Lighting.

c) The usage types for Substitution type 63 are:

i. peak, or

ii. off-peak, or

iii. as appropriate to the metering configuration.

13.4.4 Substitution/Estimation Type 64 – Agreed Method

a) The *Code Participant*, the applicable *user* and the *Network Operator* may agree to use another method of substitution (which may be a modification of an existing Substitution Type) where none of the existing Substitution Types is applicable.

b) The specifics of this Substitution Type may involve a globally applied method or a site-specific method.

13.4.5 Substitution/Estimation Type 65 – Estimation by Average Daily Consumption

a) Value = Average daily consumption × Number of days required to be substituted

b) Substitution Type 65 is to be used only when the consumption from the same, or similar, *meter* read period last year and the consumption from the previous *meter* read period are not available.

14 Schedule 10 – Metering Installation Type 7 – Energy Calculation

14.1 Requirement to Produce Energy Data

14.1.1 Agreed market loads

a) Type 7 *meter*s are associated with un-metered loads, as defined in article 3.9(2) of the *Metering Code*.

b) The *metrology coordinator* and *IMO* may, from time to time, agree to classify other types of load as unmetered, where, in their opinion, the load is similar in nature to the existing unmetered loads.

c) As a guide, a similar load is likely to be one that is uneconomic to *meter* individually *{e.g. the cost of type 6* metering *is not much less than the likely cost of electricity consumed over the meter lifetime}* and where it is not practical to *meter* the consumption points at an economically viable aggregate level *{e.g. it is not possible to connect all consumption points in the load behind a single meter to give a larger aggregate reading at an economical level}*.

14.1.2 Application to device types

a) The agreed market load that is published by the *metrology* Coordinator will be generic in nature (for example, street lighting). For each agreed market load there may be one or more device types which are listed in the *Load Table* developed in accordance with clause 14.1.6 of this Schedule 11

14.1.3 Application of NMI

a) *Energy data* for an unmetered load is calculated by NMI data stream. A NMI is assigned for each unique combination of:

- Financially Responsible *Code Participant*,
- End-use customer,
- LNSP,
- TNI, and
- Distribution loss factor.

The NMI may contain different agreed market loads and/or different device types, but they must have the same Financially Responsible *Code Participant*, end-use customer, LNSP, TNI and Distribution loss factor.

b) Where permitted by the *Code* or guidelines issued by the *IMO*, an unmetered load may be included in the NMI for a related metered load, where the number of devices is small, for example watchman lights, the energy consumption of those devices is immaterial relative to the total energy consumption for that NMI, and the Financially Responsible *Code Participant*, end-use customer, LNSP, Marginal loss factor and Distribution loss factor are the same.

14.1.4 Inventory Table

a) The *Network Operator*, retailer and Customer must agree and maintain the following inventory information for each load type for each NMI:

1 The device type.

2 The start date, being the first date on which this device type is to be included in the *energy data* calculations.

3 The end date, being the last date upon which the device type is to be included in the *energy data* calculations.

4 The proportion of the load that is attributable to the NMI. The total proportion attributable to all NMIs must equal 100%.

5 The number of devices of this type. This may vary with time and a complete history of the applicable numbers must be maintained for a seven-year period.

6 The Responsible person must use its reasonable endeavours to update the inventory for the NMIs for which it is responsible and must communicate any material changes to the affected *Code Participants*.

7 The relevant time code (on-off) table.

8 The applicable loss factor, either directly or through an associated characteristic (such as the distribution zone). This defines the efficiency with which power is transported to the point of consumption.

9 The maximum daily energy reading for validation purposes.

10 The minimum daily energy reading for validation purposes (which may be zero).

11 Optionally, where trading interval data is required, the number of trading intervals in the day for which a zero value is acceptable.

b) The information must be agreed prior to the installation of any new load and must be regularly reviewed and maintained in line with good industry practice.

14.1.5 Time code table

a) The *Network Operator*, *retailer* and *Customer* must agree and maintain the on-off times for each specific load type.

b) These will be one of the following:

1 The number of hours in the day during which the load is on.

2 The number of off-peak hours in the day during which the load is on and the number of peak hours in the day during which the load is on.

3 A load profile indicating whether the load is on or off in each trading interval.

c) The on-off times will be allowed to vary with time. I.e. the times on for a particular period - such as day, week, month, quarter or year - may differ in succeeding periods.

d) The information must be agreed prior to the installation of any new load and regularly reviewed and maintained in line with good industry practice.

{Note: for example, a load might be defined as follows:

Dec – Feb:	*10 hours per day*
Mar – May:	*12 hours per day*
June – Aug:	*14 hours per day*
Sep – Nov:	*12 hours per day*

While another might be defined as:

	Interval Status										
	0:00	0:30	1:00	1:30	2:00	2:30	3:00	3:30	4:00	4:30	etc.
Jan	1	1	1	1	1	1	1	1	1	1	etc.
Feb	0	0	0	1	1	1	1	1	1	1	
Mar	0	0	0	0	0	1	1	1	1	1	
Apr	0	0	0	0	0	0	0	0	1	1	
May	0	0	0	0	0	0	1	1	1	1	
etc.	etc.										

where 1 indicates the device is on and 0 indicates it is off.}

14.1.6 Load Table

a) The load table will record the calculated device wattage. This is the agreed average daily consumption for the device together with any control gear.

b) The load rating should represent the average anticipated power rating in the applicable time period. Where possible the device load should be determined from measurement tests conducted by a suitable accredited laboratory.

c) The information must be agreed prior to the installation of any new load and regularly reviewed and maintained in line with good industry practice.

14.2 Type 7 Energy Calculation

14.2.1 The default method of calculation is based upon a calculation from the inventory para*meter*s, load table and on-off table.

$$C_{NMI,i,\tau} = \frac{(k \times n \times h \times P \times L)}{1000}$$

and

$$C_{NMI,\tau} = \sum C_{NMI,i,\tau}$$

Where:

$C_{NMI,i}$	is the consumption, in *energy units*, for an NMI for a device type, *i*, for a period, τ.
C_{NMI}	is the consumption, in *energy units*, for an NMI across all device types, for a period, τ.
k	is the proportion of the device load attributable to the NMI.
n	is the number of devices of the applicable type for the NMI.
h	is the number of hours in the period during which the device is switched on. For the avoidance of doubt, this does not have to be an integer number – fractions of hours are permitted.
P	is the average power consumption for the device, expressed in Watts.
L	is the applicable loss factor.
τ	is the applicable period, for example trading interval, day, peak period, off-peak period, shoulder period, etc.

14.2.2 Where half hourly consumption data is required, this shall be calculated as either:

a) Where no interval “on-off” data is available, consumption in each interval shall be the calculated power consumption for the day divided by the number of trading intervals in the day.

Or,

b) Where hours on in peak/off peak/shoulder periods is available then:

1 For every interval in the off-peak period, the consumption shall be the power consumption for the off-peak period divided by the number of trading intervals in the off-peak period.

2 For every interval in the peak period, the consumption shall be the power consumption for the peak period divided by the number of trading intervals in the peak period.

3 For every interval in the shoulder period, the consumption shall be the power consumption for the shoulder period divided by the number of trading intervals in the shoulder period.

Or,

c) Where interval “on-off” data is available:

1 For every trading interval marked as “off” the consumption shall be zero.

2 For every trading interval marked as “on” the consumption shall be the total daily consumption divided by the number of “on”-intervals in the day.

{Note: this is equivalent to calculating the interval consumption from first principles using the calculation method in 17.2.1 above.

For example, consider that we require a reading for the period 1 Feb to 30 Apr for the hypothetical load described below:

Rating	*150W*
Inventory	*1000*
Loss Factor	*0.97*
Proportion	*1*
Period	*On-time*
1 Dec	*20:00 to 05:00*
1 Mar	*19:00 to 06:00*
1 Jun	*18:00 to 07:00*
1 Sep	*19:00 to 06:00*

This would be calculated as follows:

Period	*Applicable On-time*	*Consumption*
1 Feb to 28 Feb	*28 days at 9 hours/day*	*= 1 × 1000 × 9 × 150 × 0.97 Wh/day* *= 1309.5 kWh/day* *= 72.75 kWh for each half hour trading interval for which the load is on* *= 36.666 MWh in total*
1 Mar to 30 Apr	*61 days at 11 hours per day*	*= 1 × 1000× 11 × 150 × 0.97 per day* *= 1600.5 kWh/day* *= 72.75 kWh for each half hour trading interval for which the load is on* *= 97.6305 MWh in total*
Grand total for period from 1 Feb to 30 Apr	*923 hours*	*= 134.2965 MWh for the period as a whole.*

End of example}

15 Schedule 11 – Metering Installation Type 7 – Validation and Substitution

15.1 Requirement to Perform Validation

15.1.1 *Energy data* calculations are required to be validated in accordance with clause 3.5.4 of this *Metrology Procedure*.

15.1.2 The validation rules that may be applied to the *energy data* calculated for a Type 7 *metering installation* are:

a) Check against maximum permitted value

The calculated value will be automatically checked after calculation and if the maximum value is exceeded substitution will be performed.

b) Check for null (missing) energy data

A check for null (missing) *energy data* will be performed for each type 7 NMI data stream for an individual day and, where necessary, for each trading interval. Any null values will be substituted.

{Note: retailers currently only receive and use daily data for type 7 loads. Now that the Market Rules specify that the Notional Wholesale Meter (NWM) calculation is performed by the IMO, there is not currently any need for this data at interval level (the Code states that it is needed to support the NWM calculation). Furthermore, during the initial period of code operation the existing systems will continue to be used by both Western Power Metering *and the only retailer of Type 7 meters and these systems do not make use of interval data. Hence the Code requirement for interval readings is not deemed to be binding at this time. The wording of the Metrology Procedures is intended to cope with the future situation, which may never arise, where such interval data is required again.}*

c) Check of standing data

Check the Inventory tables, Load tables and On/Off tables to ensure that the correct version of the tables are being used for the *energy data* calculations. The *Network Operator* will perform such checks periodically in accordance with good industry practice. The results of these audits of the tables will be circulated to the relevant parties. The interval between checks will not exceed six months. If an error is detected then substitution will be performed on all *energy data* for affected type data since the time of the last check.

{Note: It will be sufficient to manually calculate the substituted values at the aggregate level for periods for which billing has already occurred. This will then allow the error in the billing to be determined without placing an onerous burden on the Network Operator or Retail staff. E.g. if the error has been in place for six months it would be sufficient to determine the consumption for the six month period. This could then be compared to the previous calculated consumption and the necessary billing corrections performed.}

d) Check against minimum permitted value

Check against a nominated minimum value or alternatively a 'zero' check that tests for an acceptable number of zero interval values per day.

i. If no trading interval data is required, then if the calculated daily consumption is less than the minimum specified consumption, the value will be rejected and substitution performed.

ii. If trading interval data is required, then if the consumption in any trading interval is less than the minimum specified consumption, or if the total number of trading intervals with a reading of zero exceeds the allowed number, then the values for the day and all trading intervals will be rejected and substitution performed.

e) Check that the *energy data* date > previous *energy data* date. If the *energy data* date is earlier than the last received *energy data* date then the value is rejected and substitution will occur.

15.2 Requirement to Perform Substitution

15.2.1 In accordance with clause 5.6.3 of this *Metrology Procedure*, *energy data* for a type 7 *metering installation* will require to be substituted where the *energy data* calculation fails the validation tests.

15.2.2 The approved substitution types are

a) Method 71 – recalculation

The preferred substitution method consists of the recalculation of the energy consumption using the latest time-code, load and inventory tables and the formulae defined in clause 14.2, Type 7 Energy Calculation.

b) Method 72 – revised tables

Where the value derived in clause 14.2, Type 7 Energy Calculation

is found to be incorrect due to an error in the inventory, time-code or load tables, the value will be substituted with the value derived as per method 71 but utilizing the most recent tables for which no error is evident.

c) Method 73 – revised algorithm

Where the error in the calculation of the *energy data* in clause 14.2, Type 7 Energy Calculation

, is due to an error in the algorithm, the *energy data* is substituted with the most recent *energy data* for which there was no error.

Thus, if we are calculating the consumption for a period and it is determined that the algorithm is being applied incorrectly then the calculated value for the last undisputed period will be determined. This will then, if necessary, be pro-rationed by the duration of the periods to determine the applicable substituted value.

{For example, consider a load for which we are calculating the load for the months of April-May. It is determined that the algorithm is in error and the last period calculated without error was February-March. If the consumption value for 31 March had been available and was 3.7 kWh then the calculation would have been:

Reading on 31 March	*= 3.7 kWh*
Days in April-May	*= 61 days*
Substituted consumption for each day in April May	*= 3.7 kWh*
Substituted value for entire period	*= 61 $\times$ 3.7 = 225.7 kWh*

Alternatively, if we do not have daily or interval data but the aggregate consumption was 220 kWh. We could calculate the consumption as:

Days in April-May	*= 61 days*
Days in February March	*= 59 days*
Substituted value	*= (61/59) × 220 = 227.46 kWh*
Substituted value for each day in April May	*= 227.46/61 = 3.7289 kWh*

End of example}

d) Substitution Method 74: Agreed Method.

The *Code Participant*, the applicable user and the *Network Operator* may agree to use another method of substitution (which may be a modification of an existing substitution method) where none of the existing substitution methods is applicable.

The specifics of this substitution method may involve a globally applied method or a site-specific method.

16 Schedule 12 - Metering Statuses

This schedule shows the statuses received from the metering systems and how these translate into the statuses disseminated by the *Network Operator*. It is provided for information purposes only.

The following table shows the bits that can be set for interval data within the MV90 systems that send data to the HUB system and the status code that they correspond to. For example if bit 0 is set to 1 then this indicateds that a power outage has occurred during the interval.

Bit	Description	Source of Status	Interval Status Code
15	*Reserved*		No Interval Status Code. This bit position should never be set.
14	*Reserved*		No Interval Status Code. This bit position should never be set.
13	*Reserved*		No Interval Status Code. This bit position should never be set.
12	Load Control	Recording Device	LC – Load Control
11	Test Mode	Recording Device	TM – Test Mode
10	Time Reset Occurred	Recording Device	TR – Time Reset Occurred
9	Watchdog Time-out	Recording Device	WT – Watchdog Time Out Occurred
8	Reset Occurred	Recording Device	BR – Reset
7	Clock Error	Recording Device	CL – Clock Error
6	Data Missing	Recording Device or MV90 Manual Edit	LA – Lapse in Data
5	ROM Checksum Error	Recording Device	RO – ROM Checksum Error
4	RAM Checksum Error	Recording Device	RA – RAM Checksum Error
3	CRC Error	Recording Device	CR – CRC Checksum Error
2	Long Interval (Missing For Mag Tape)	Recording Device	LI – Long Interval
1	Short Interval (False for Mag Tape)	Recording Device	SI – Short Interval

0	Power Outage	Recording Device or MV90 Manual Edit	PO – Power Outage

Figure 1. MV90 interval status codes.

The following table indicates the statuses that MV90 can set for each channel of data transmitted to the HUB system. For example if Bit 3 is set then that will indicate to the HUB that the data has been estimated and HUB will report the data as estimated when transmitting it onwards to the *Code Participants.*

Bit	Description	Source of Status	Channel Status Code
15	*Reserved*		No Channel Status Code. This bit position should never be set.
14	*Reserved*		No Channel Status Code. This bit position should never be set.
13	*Reserved*		No Channel Status Code. This bit position should never be set.
12	Estimation type indicator	Estimation (Check/Redundant/Historical/Linear)	The translation is based on the combined pattern of bits11 and 12 Bit Pattern will show one of EH, EL, CK with ES (Bit 3) or RD with RE (Bit 2) It is not expected the Bit 12 is set without either Bit 2 or Bit 3 set at the same time.
11	Estimation type indicator	Estimation (Check/Redundant/Historical/Linear)	It is not expected the Bit 11 is set without either Bit 2 or Bit 3 set at the same time.
10	Harmonic Distortion	Recording Device	DI – Harmonic Distortion
9	Alarm	Recording Device	LR – Alarm / Error
8	Energy Type (Register Changed)	MV90 Data Edit	TY – Energy Type Changed
7	Parity	Recording Device	PY – Parity Error in Data
6	Excluded Data	MV90 Manual Edit	XC – Excluded Channel Data
5	Data Out of Limits	MV90 Validation	HL – Limit Check on Channel Data
4	Pulse Overflow	Recording Device or MV90	QV - Overflow of Channel Data
3	Estimated Interval (Data Correction)	MV90 Data Edit (Manual or Auto)	ES - Estimated Channel Data

2	Replaced Interval (Data Correction)	MV90 Data Edit (Manual/Auto/TD/Create)	RE - Replaced Channel Data
1	Added Interval (Data Correction)	MV90 Data Edit	AD - Added Interval
0	Retransmitted / Updated Data	Manual export – MV90 Type export	UP – Updated Data

Figure 2. MV90 Channel status codes.

The following enclosure contains an example of the rules for mapping MV90 Channel Statuses and Interval Statuses to equivalent HUB attributes.

MV90 Input | **HUB Reading Record Fields**

Channel Status Bit Pattern | **Interval Status Bit Pattern**

15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	Channel Status	Interval Status	Read Type	Error Code	Estimation/Subs Method		Reason Code	App Seq
																																				T1-T4 *Meter*	T5 *Meter*		
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	no value	no value	A	no value	no value	no value	no value	3
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	x	no value	**lowbit**	A	RW155	no value	no value	no value	8
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	x	no value	LA	A	**REXxx**	no value	no value	85	9
x	x	x	0	0	x	x	x	x	0	x	x	x	1	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	RE	no value	S	RW132	18	55	93	11
x	x	x	0	1	x	x	x	x	0	x	x	x	1	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	RE	no value	S	RW132	18	55	93	11
x	x	x	1	0	x	x	x	x	0	x	x	x	1	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	RE	no value	S	RW132	18	55	93	11
x	x	x	1	1	x	x	x	x	0	x	x	x	1	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	RE	no value	S	RW132	18	55	93	11
x	x	x	0	0	x	x	x	x	0	x	x	1	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	ES	no value	S	RW132	18	55	94	11
x	x	x	0	1	x	x	x	x	0	x	x	1	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	ES	no value	S	RW132	17	54	94	11
x	x	x	1	0	x	x	x	x	0	x	x	1	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	ES	no value	S	RW132	18	55	94	11
x	x	x	1	1	x	x	x	x	0	x	x	1	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	ES	no value	S	RW132	18	55	94	11
x	x	x	x	x	x	x	x	x	1	x	x	x	1	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	XC	no value	S	**REyyy**	no value	no value	97	13
x	x	x	x	x	x	x	x	x	1	x	x	1	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	XC	no value	S	**REyyy**	no value	no value	97	13
x	x	x	x	x	x	x	x	x	1	x	x	0	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	XC	no value	A	**REyyy**	no value	no value	97	19
x	x	x	x	x	x	x	x	x	0	x	x	0	0	x	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**lowbit**	no value	A	RW132	no value	no value	no value	17
x	x	x	x	x	x	x	x	x	0	x	x	0	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	**lowbit**	**lowbit**	A	**RWaaa**	no value	no value	no value	21
x	x	x	x	x	x	x	x	x	0	x	x	0	0	x	x	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	X	**lowbit**	LA	A	**REXxx**	no value	no value	85	23

MV90 Input — **HUB Reading Record Fields**

Channel Status Bit Pattern — **Interval Status Bit Pattern**

15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	Channel Status	Interval Status	Read Type	Error Code	Estimation/Subs Method T1-T4 *Meter*	Estimation/Subs Method T5 *Meter*	Reason Code	App Seq
x	x	x	x	x	x	x	x	x	1	x	x	0	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	XC	**lowbit**	A	**REyyy**	no value	no value	97	25
x	x	x	x	x	x	x	x	x	1	x	x	0	0	x	x	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	X	XC	LA	A	**REzzz**	no value	no value	**85**	27
x	x	x	0	0	x	x	x	x	0	x	x	0	1	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	RE	**lowbit**	S	**RWaaa**	18	55	93	29
x	x	x	0	1	x	x	x	x	0	x	x	0	1	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	RE	**lowbit**	S	**RWaaa**	18	55	93	29
x	x	x	1	0	x	x	x	x	0	x	x	0	1	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	RE	**lowbit**	S	**RWaaa**	18	55	93	29
x	x	x	1	1	x	x	x	x	0	x	x	0	1	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	RE	**lowbit**	S	**RWaaa**	18	55	93	29
x	x	x	0	0	x	x	x	x	0	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	ES	**lowbit**	S	**RWaaa**	18	55	94	29
x	x	x	0	1	x	x	x	x	0	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	ES	**lowbit**	S	**RWaaa**	17	54	94	29
x	x	x	1	0	x	x	x	x	0	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	ES	**lowbit**	S	**RWaaa**	18	55	94	29
x	x	x	1	1	x	x	x	x	0	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	ES	**lowbit**	S	**RWaaa**	18	55	94	29
x	x	x	0	0	x	x	x	x	0	x	x	x	1	x	x	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	X	RE	LA	S	**RExxx**	no value	no value	85	31
x	x	x	1	1	x	x	x	x	0	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	X	ES	LA	S	**RExxx**	no value	no value	85	31
x	x	x	x	x	x	x	x	x	1	x	x	x	1	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	XC	**lowbit**	S	**REyyy**	no value	no value	97	33
x	x	x	x	x	x	x	x	x	1	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	0	x	x	x	x	x	X	XC	**lowbit**	S	**REyyy**	no value	no value	97	33
x	x	x	x	x	x	x	x	x	1	x	x	x	1	x	x	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	X	XC	LA	S	**REzzz**	no value	no value	**85**	35
x	x	x	x	x	x	x	x	x	1	x	x	1	0	x	x	x	x	x	x	x	x	x	x	x	1	x	x	x	x	x	X	XC	LA	S	**REzzz**	no value	no value	**85**	35

NOTES

Comments Column is not part of the mapping table.
A LA Interval Status, this takes precedence over all other Interval Statuses
An XC Channel Status takes precedence over all other Channel Statuses
An RE or ES Channel Status takes precedence over other Channel Statuses apart from XC
If both the bits for an RE and ES Channel Status are set, then the RE takes precedence over the ES
Application Sequence Column attempts to provide an order of the mapping rules

LOWBIT - this is a keyword to represent a method of determining the appropriate status.

MV90 Input																																HUB Reading Record Fields							
Channel Status Bit Pattern																Interval Status Bit Pattern																							
15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	Channel Status	Interval Status	Read Type	Error Code	Estimation/Subs Method		Reason Code	App Seq
																																				T1-T4 *Meter*	T5 *Meter*		

Where the Channel Status and/or Interval Status has more than one value, and there is no explicit combination in the table, the rule is to take the lowest set bit

Error Code RWaaa - HUB to assign the actual warning code during technical design. The code represent interval and channel status both present
Error Code RExxx - HUB to assign the actual code during technical design. The code represents LA Interval Status exception.
Error Code REyyy - HUB to assign the actual code during technical design. The code represent XC Channel Status exception.
Error Code REzzz - HUB to assign the actual code during technical design. The code represents both LA & XC exceptions occurred.
Error Code RW132 is a warning code that exists in HUB. Represents Channel Status Warning
Error Code RW155 is a warning code that exists in HUB. Represents Interval Status Warning

no value - no value for the column

A - Actual
S - Substituted
x - don't care if bit is set to 0 or 1

Figure 3. mapping of MV90 statuses to HUB statuses passed on to the *Code Participants*.

Schedule 13 – Data Streams

[XXX to be addressed XX]