General Notice

ELECTRICITY CONTROL BOARD

No. XXX 2026

DISTRIBUTION GRID CODE (2 OF 3 CODE DOCUMENTS): ELECTRICITY ACT, 2007

Under Section 3(4)(a) of the Electricity Act, 2007 (Act No. 4 of 2007), the Electricity Control Board, with the prior approval of the Minister of Industries, Mines and Energy, has made the Distribution Grid Code set out in the Schedule.

PROF. TJAMA TJIVIKUA
DEPUTY CHAIRPERSON OF THE ELECTRICITY CONTROL BOARD Windhoek,
_____ 2026

SCHEDULE

ARRANGEMENT OF CODES

CHAPTER 1
INTRODUCTORY PROVISIONS

PART 1
DEFINITIONS AND OBJECTIVES

1. Definitions
2. Objectives of this Code

PART 2
APPLICATION OF DISTRIBUTION GRID CODE

3. Application of this Code to the distribution network
4. Application of this Code to distribution operations
5. Application of this Code to distribution metering
6. Application of this Code to distribution information exchange

PART 3
DISTRIBUTION POWER SYSTEM GOVERNANCE

7. The GCAC and related governance matters

CHAPTER 2
DISTRIBUTION NETWORK

PART 1
DISTRIBUTION POWER SYSTEM CONNECTION PROCESS AND PROCEDURES

8. Connection arrangement
9. Application for connection
10. Responsibilities of distributor
11. Responsibilities of customers and users

PART 2
DISTRIBUTION POWER SYSTEM TECHNICAL REQUIREMENTS

12. Protection requirements
13. Quality of supply
14. Load power factor
15. Earthing requirements
16. Distribution network interruption performance indices
17. Losses in distribution power system
18. Equipment requirements

PART 3
DISTRIBUTION POWER SYSTEM PLANNING AND DEVELOPMENT

19. Framework for distribution network planning and development
20. Approach to network investment criteria
21. General investment criteria
22. Least economic cost criteria for shared network investments
23. Least life-cycle cost criteria for customer connections
24. Investment criteria for custormers requiring a premium connection
25. Statutory or strategic investments
26. Investment criteria for connections of international customers
27. Excluded services

CHAPTER 3
DISTRIBUTION POWER SYSTEM OPERATIONS

PART 1
OPERATIONAL RELATIONS, PROCEDURES, PLANNING, CONDITIONS AND CONTROL

28. Operational responsibilities of distributors
29. Operational responsibilities of embedded generators and customers
30. Operational authority
31. Operating procedures
32. Operational liaison
33. Emergency and contingency planning
34. Operation during abnormal operating conditions
35. Independent action by participants
36. Demand and voltage control
37. Fault reporting and analysis or incident investigation
38. Distributor maintenance program
39. Testing and monitoring
40. Safety coordination
41. Disconnection and reconnection
42. Commissioning

PART 2
MAINTENANCE COORDINATION, OUTAGE PLANNING AND COMMUNICATION AND CONTROL

43. Responsibilities of distributor
44. Risk-related outages
45. Refusal or cancellation of outages
46. Communication of system conditions, operational information and distribution power system performance
47. Unplanned interruptions of supply or outages
48. Planned interruptions of supply or outages
49. Communication and control

CHAPTER 4
DISTRIBUTION POWER SYSTEM METERING

50. Principles of distribution metering
51. Responsibility for metering installations
52. Metering installation components
53. Data validation
54. Data verification
55. Metering database
56. Testing of metering installations
57. Metering database inconsistencies
58. Access to metering data
59. Confidentiality

CHAPTER 5
DISTRIBUTION POWER SYSTEM INFORMATION EXCHANGE

PART 1
INFORMATION EXCHANGE INTERFACE AND PROVISION AND EXCHANGE OF INFORMATION DURING PLANNING AND CONNECTION PROCESS

60. Information exchange interface
61. Provision and exchange of information during planning and connection process

PART 2
OPERATIONAL AND CONFIDENTIALITY INFORMATION

62. Commissioning and notification
63. Sharing of assets and resources
64. Additional information requirements
65. Communication and liaison
66. Data storage and archiving
67. Confidentiality of information

PART 3
CYBER SECURITY

68. Cyber security minimum standards compliance
69. Cyber security requirements
70. Compliance with national requirements for cyber security

CHAPTER 6
DISTRIBUTION POWER SYSTEM MARKET CODE

PART 1
DISTRIBUTION CAPACITY
ALLOCATION AND CONGESTION MANAGEMENT

71. Non-discrimination for distribution capacity allocation and congestion management
72. Congestion management

CHAPTER 7
GENERAL

73. Transitional provisions for cyber security

ANNEXURES

ANNEXURE 1: SAMPLE CONFIDENTIALITY AGREEMENT FOR INFORMATION TRANSFER TO THIRD PARTIES

CHAPTER 1
INTRODUCTORY PROVISIONS

PART 1
DEFINITIONS AND OBJECTIVES

Definitions

1. In this Code a word or an expression to which a meaning has been assigned in the Act has that meaning unless the context otherwise indicates –

"abnormal operating conditions" mean all conditions deviating from normal operating conditions;

"administrative losses" mean meter reading errors and any unbilled energy resulting from billing system operational errors;

"applicant" means a potential user intending to connect to the electricity distribution power system;

"avoided cost rate" means the average cost per unit of electric energy which, if not provided by an embedded generator, a distributor would generate itself or purchase from another source;

"Board" means the Electricity Control Board established by Section 2 of the Electricity Act No.4 of 2007;

"CAIDI" means Customer Average Interruption Duration Index which is the average duration of an interruption of supply, calculated as the ratio of the total duration of interruptions of supply to the total number of interruptions of supply during the year;

"capacity" means the potential load that electrical equipment or a network can transfer;

"connection agreement" means an agreement detailing the conditions under which the distributor intends to connect a customer;

"connection charges" mean the charges payable by the customer to cover the costs associated with the connection to the transmission or distribution network as applicable;

"consumer" means consumer as defined in Section 1 of the Act;

"customer" means a customer as defined in Section 1 of the Act;

"customer connection information guide" means a document prepared and published by the distributor which contains all information regarding an application to connect to the relevant distributor network;

"customer dedicated assets" mean assets created for the sole use of a customer, to meet the technical specifications of the customer, and are unlikely to be shared in the planning horizon of the distributor by any other customer;

"customer interruption cost" means the cost, in Namibia dollars per kWh, to customers due to interruptions of supply of the provision of electricity;

"distribution network" means the distribution power system owned and operated by a distributor;

"distribution power system impact assessment studies" mean studies to model and assess the impact of connecting a customer load or an embedded generator on the distribution power system;

"distribution power system operator" means the entity responsible for short-term reliability of the interconnected distribution power system, which is in charge of controlling and operating a distribution power system;

“distribution use of system charges” mean unbundled regulated tariffs charged to distribution network services customers for making capacity available to and for use of the distribution power system and transmission connected customers for their fair contribution to distribution subsidies;

“distributor” mean a person who holds a distribution licence issued under the Act for the distribution of electricity;

“distributor cost” means the distribution investment cost incurred by the distributor;

“domestic supply” means the supply taken by a customer occupying a residential dwelling;

“economic cost” means the total cost of the electricity related investment to both the distributor and the customer;

“embedded generator” means a person who -

(a) operates a generation plant or a generating unit that is connected to a customer’s network that connects to the distribution or transmission system; or

(b) operates a generating unit that is directly connected to a distribution power system; or

(c) desires to undertake the activities contemplated in (a) or (b);

“energy storage provider” means a person operating a licensed RESS, whether such RESS is subject to an energy storage licence or operated under another licensed electricity undertaking;

“excluded services” mean the services requested by customers that are excluded from the regulated activities and funded directly by the customer requesting the service;

“forced outage” means an outage that occurs when a component is taken out of service immediately, either automatically or as soon as switching operations can be performed, as a direct result of abnormal operating conditions, emergency conditions or human error;

“GCAC” means the Grid Code Advisory Committee established under the Transmission Grid Code;

“generating unit” means a device used to produce electrical energy;

“high voltage” means nominal voltage levels greater than 33 kV;

“information” means knowledge that can be exchanged and always expressed by some type of data stored and processed either electronically or otherwise;

“information owner” means the party to whose system or installation the information pertains;

“international customers” mean customers who are situated outside the borders of the Republic of Namibia and provided with electricity by the distributor;

“interruption of supply” means the total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system but this does not include power quality issues such as, but not limited to, sags, swells, impulses, or harmonics;

“islanding” means the capability of generating units to settle down at nominal speed, supplying own auxiliary load after separation from the grid at up to full load pre-trip conditions;

“kWh” means a measure of electrical energy equivalent to a power consumption of one thousand watts for

one hour;

“least economic cost” means least life-cycle cost to both the distributor and the customer related to the electricity infrastructure;

“least life-cycle cost” means the sum of all cost categories from installation to decommissioning when evaluating different investment alternatives;

“least life-cycle distributor cost” means the least life-cycle cost to the distributor;

“losses” means energy for which the distributor does not recover revenue and includes technical losses, non-technical losses and administrative losses;

“low voltage” means nominal voltage levels up to and including 1 kV;

“medium voltage” means the nominal voltage levels greater than 1 kV but not greater than 33 kV inclusive;

“metering” means a reliable process of measuring electrical energy supply or consumption;

“metering installations” means all meters, fittings, equipment, wiring and installations used for measuring the flow of electricity;

“metering service provider” means a person contracted by the distributor to provide metering services;

“MSB” means the modified single buyer established under the Modified Single Buyer Market Structure, adopted by the Government of the Republic of Namibia, in April 2019;

“network” means the electrical infrastructure over which electrical energy is transported from source to point of consumption;

“non-technical losses” means losses due to theft of electrical energy, meter error or inaccurate meter reading;

“normal operating conditions” means operating conditions where the system frequency, voltage and equipment loading are within their statutory, contractual and design limits and no network component on the relevant part of the distribution power system is out of service due to a forced outage or due to a planned outage;

“NRS” means a National Rationalised Standard;

“offer to connect” means a quotation issued by the distributor to the applicant indicating the technical and commercial conditions upon which a connection agreement can be entered;

“participant” means a person registered with a licensee in their licensed area or licensed by the Board in terms of the Act such as, but not limited to, embedded generators, energy storage providers, traders, distribution licensees, transmission licensees and the system operator;

“planned outage” means an outage of equipment that is requested, negotiated, scheduled and confirmed at a minimum of 14 days prior to maintenance or repairs taking place;

“point of connection” means the electrical node on a distribution power system where the assets of a customer are physically connected to the assets of a distributor;

“point of supply” means the physical point on the network where electricity is supplied or deemed to be supplied to a customer and at which the supply is metered;

“power factor” means the ratio of real power, in kW, to apparent power, in kVA, measured over the same integrating period;

“premium connection” means the requirements of the customer exceed the specifications of a standard

connection;

“quality of supply” means the technical parameters that describe the electricity supplied to customers;

“reliability” means a measurement of the continuity of supply;

“RESS” means a regulated energy storage system device or set of devices which uses electrical energy as input, stores this energy internally and supplies electrical energy as output at a later time to a transmission or distribution power system or a mini-grid;

“SAIFI” means the system average interrupton frequency index which indicates the total duration 1 of interruption of supply for the average customer during a predefined period of time and it is calculated as a ratio of the total number of interruptions of supply in a year to the total number of customers served;

"SCADA” means supervisory control and data acquisition;

“shared network investment” means -

(a) investment in shared infrastructure, i.e., non-dedicated assets;

(b) investment required to provide adequate upstream network capacity;

(c) investment required to maintain or enhance supply reliability and quality to attain the limits or targets, determined in the Namibia Quality of Supply Standards, on existing network assets; and

(d) the refurbishment of existing standard dedicated connection assets;

“standard connection” means the lowest life-cycle cost design that meets the specifications in terms of the Namibia Quality of Supply and Quality of Service Standards for a technically acceptable solution and “standard supply” has a corresponding meaning;

“System Average Interruption Duration Index (SAIDI)” means the index which indicates how often the average customer experiences a sustained interruption of supply over a predefined period of time and is calculated as a ration of the sum of all total customer interruption of supply durations in a year to the total number customers served in that year;

“system operator” means the entity responsible for short-term reliability of the interconnected power system, which is in charge of controlling and operating the transmission system and dispatching generation, or balancing the supply and demand, in real time;

“technical losses” means conductor losses, transformer losses, metering accuracy losses and energy consumed by the meter itself;

“the Act” means the Electricity Act, 2007 (Act No. 4 of 2007);

“this Code” means this Distribution Grid Code;

“trader” means a person licensed to buy electricity or ancillary services as a commercial activity for the selling of electricity or services to other licensees or customers;

“Transmission Grid Code” means the Transmission Grid Code published in Government Gazette No. …. of …….. 202…, Government Notice No. …. of …… 202…;

“unit” means a turbine alternator and all the related equipment, including the step-up transformer, operated together to produce electricity; and

“user” a customer or an embedded generator connected to the distribution power system.

Objectives of this Code

2. (1) The objectives of this Code are to -

(a) establish the governing structure and procedures that allow a person to use the distribution power system and to permit the distribution power system to be planned and operated safely, reliably, efficiently and economically;

(b) be objective, transparent, non-discriminatory and consistent with Government policy;

(c) define the obligations and accountabilities of all the parties;

(d) specify minimum technical requirements for the distribution power system;

(e) ensure that relevant information is made available;

(f) ensure that a service provider operates -

(i) according to the licence conditions imposed under the Act; and

(ii) transparently and provides non-discriminatory access to its defined services;

(g) ensure that a customer honours its mutual obligations under this Code and that there is agreement on the mutual obligations;

(h) set the basic rules of connecting to the distribution power system;

(i) ensure that all users of the distribution power system are treated in a non-discriminatory manner;

(j) specify the technical requirements to ensure the safety and reliability of the distribution power system;

(k) set out the responsibilities and roles of the participants as far as the operation of the distribution power system is concerned and more specifically issues related to -

(i) reliability, security and safety of the distribution power system;

(ii) operational authority, communication, emergency and contingency planning of the distribution power system;

(iii) operation of the distribution power system under abnormal operating conditions; and

(iv) field operation, maintenance and maintenance coordination or outage planning;

(l) specify safety coordination and management criteria to be applied by a distributor to meet the distribution conditions and obligations;

(m) specify demand and voltage control strategies and methods used for the control of distribution power system parameters;

(n) ensure a metering standard for all current and future participants;

(o) specify metering requirements to be adhered to;

(p) clarify levels of responsibility relating to metering requirements contemplated in paragraph (o);

(q) define the reciprocal obligations of participants with regard to the provision and exchange of

planning, operational and maintenance information for the implementation of this Code.

(2) Information exchanged between parties governed by this Code is not confidential unless otherwise stated.

(3) The NRS 057 metering specifications must be used as the metering requirements for this Code.

(4) Despite subcode (3), the Board may approve a deviation from the NRS specifications should it find them inadequate or divergent from the principles of this Code.

(5) If an aspect is not fully or clearly addressed in the NRS 057 specifications or if a conflict arises between the provisions of this Code and the NRS 057 specifications, this Code takes precedence over the NRS 057 specifications.

PART 2
APPLICATION OF DISTRIBUTION GRID CODE

Application of this Code to the distribution network

3. The provisions of this Code relating to the distribution power system apply to all users of the distribution power system including distributors, embedded generators, energy storage providers, consumers, supply licensees, re-sellers and any other entities with equipment connected to the distribution power system.

Application of this Code to distribution operations

4. The provisions of this Code relating to distribution operations apply to all users of the distribution power system including distributors, embedded generators, energy storage providers, consumers and any other entities with equipment connected to the distribution power system.

Application of this Code to distribution metering

5. (1) The provisions of this Code relating to distribution metering apply to all participants in respect of a metering point at the boundary of the distribution power system.

(2) A metering point relating to an embedded generator which will sell its output to any person via the transmission power system, and not to a distributor, must be governed by the relevant provisions of the Transmission Grid Code.

(3) The provisions of this Code relating to distribution metering set out provisions relating to -

(a) main metering installations and check metering installations used for the measurement of active and reactive energy;

(b) the collection of metering data;

(c) the provision, installation and maintenance of equipment;

(d) the accuracy of all equipment used in the process of electricity metering;

(e) adherence to testing procedures;

(f) storage requirements for metering data;

(g) competencies and standards of performance; and

(h) the relationship of entities involved in the electricity metering industry.

Application of this Code to distribution information exchange

6. (1) The provisions of this Code relating to distribution information exchange apply to distributors, supply licensees, embedded generators, consumers and resellers.

(2) The information requirements specified in this Code are supplementary to the provisions relating to distribution information exchange therefore in the event of inconsistencies between a provision of this Code and a provision relating to distribution information exchange with regard to information exchange, the requirements of the provisions relating to distribution information exchange take preference.

PART 3
DISTRIBUTION POWER SYSTEM GOVERNANCE

The GCAC and related governance matters

7. Chapter 2 of the Transmission Grid Code applies with the necessary changes to this Code and for this purpose -

(a) under code 6(1)(f) of the Transmission Grid Code, another two members representing distributors must be appointed; and

(b) any reference to the Transmission Grid Code is deemed to be a reference to this Code.

CHAPTER 2
DISTRIBUTION NETWORK

PART 1
DISTRIBUTION POWER SYSTEM CONNECTION PROCESS AND PROCEDURES

Connection arrangement

8. (1) A customer seeking a new connection to the distribution power system must apply in writing using the application form referred to in subcode (2) to connect to the distribution power system with the relevant distributor.

(2) A distributor must develop its own application form which at minimum, must require the applicant seeking a new connection to the distribution power system to provide the -

(a) type, capacity, voltage and requested date for the proposed connection;

(b) location of the proposed connection;

(c) test and commissioning results;

(d) safety coordination;

(e) electrical diagrams and connection point diagrams; and

(f) any additional information the distributor may require to adequately assess the application to connect.

(3) A customer applying for a connection to the distribution power system should provide additional information on devices such as, but not limited to, inverters, filters, fluctuating loads, capacitor banks and reactors that could affect the performance of the distribution power system.

(4) Embedded generators must specify, with all relevant details, in their application for connection if the generator facility to be connected has black-start and quick start capabilities.

(5) On receiving the application for connection the distributor must comply with all other requirements relevant to the connection process specified in this Code.

Application for connection

9. (1) On receipt of the application contemplated in code 8 the distributor must determine whether the applicant can be connected to the existing system or what technical improvements are required to enable the new connection.

(2) If the distributor determines that transmission system works are required to connect the customer, the distributor must -

(a) notify the relevant transmission licensee of the application contemplated in subcode (1) without delay;

(b) enter into consultations with the transmission licensee regarding -

(i) the best manner in economic and technical terms, for connecting that new customer to the network; or

(ii) whether the new customer should be connected and supplied by the transmission or supply licensee.

(3) The consultations contemplated in subcode (2)(b) must -

(a) seek a cost effective and technically sound manner to connect the new customer; and

(b) consider the potential to supply other existing and future customers of the distribution or supply licensee or the transmission licensee at or near the location of the new customer.

(4) If the distribution or supply licensee can connect other existing or potential customers at or near to the proposed location of the new customer, then the distribution or supply licensee must connect and supply the new customer and enter into corresponding agreements with the transmission licensee.

(5) If the condition contemplated in subcode (4) is not met then the transmission or supply licensee must connect and supply the new customer unless the transmission licensee and the distribution licensee agree otherwise which agreement is subject to approval by the Board.

(6) The distributor must provide an offer to connect and if accepted by the customer, both parties must enter into a connection agreement.

(7) The connection agreement referred to in subcode (6) must include information such as, but not limited to, project planning data, inspection, testing and commissioning programs, electrical diagrams and any other information the distributor may deem necessary to proceed with the processing of the application for connection.

(8) If the application for connection has been declined by the distributor, the distributor must advise the customer on the alternative options available for connection to make the connection successful.

(9) If the customer and the distributor cannot reach an agreement on the proposed connection, the dispute resolution process outlined in Part 3 of Chapter 2 of the Transmission Grid Code must be followed by the parties.

(10) The distributor must prepare an offer to connect and provide that offer to the customer within the period specified in the Namibian Quality of Service Standard, unless otherwise agreed by the participants.

(11) The offer to connect supplied by the distributor must be fair and reasonable and may contain

alternative options available to the customer.

(12) Negotiations taking place between the parties must be conducted in good faith, documented, and information provided must be treated in a confidential manner by both parties.

Responsibilities of distributor

10. (1) The distributor -

(a) must make capacity available on its network and provide open and non-discriminatory access for the use of that capacity to all customers including embedded generators; and

(b) in exchange for making capacity available and providing access for the use of that capacity as contemplated in paragraph (a), is entitled to compensation through electricity tariffs as approved by the Board under the Act.

(2) A distributor must make available to the customers the customer connection information guide which must cover at least -

(a) the process to follow when applying for connection and supply from that distributor;

(b) information requirements of the distributor from the customer to effect an appropriate connection; and

(c) the process and related timeframes applicable to the application.

(3) The distributor must respond to the request of a customer to connect within the period specified in the Namibia Quality of Supply and Service Standards.

(4) The distributor must enter into a connection agreement with the customer prior to the actual connection to the distribution power system.

(5) The distributor must advise potential users of the expected reliability of its network.

(6) The distributor may participate in the final inspection and testing of customer equipment and facilities to be connected to its network.

(7) The distributor must maintain its distribution power system in accordance with prudent electricity practice and its licence conditions.

(8) The distributor must maintain the clearances to its live equipment in accordance with applicable laws, relevant standards and prudent electricity practices and is responsible for the planning, design and engineering specifications of the work required on the distribution power system for connection or expansion.

(9) The distributor must conduct distribution power system impact assessment studies to evaluate the impact of additional large loads or large embedded generators or major modification to the distribution power system.

(10) The assessment studies contemplated in subcode (9) must include the following:

(a) voltage impact studies;

(b) impact on network loading;

(c) fault currents;

(d) coordination of protection systems;

(e) impact on the quality of supply of the system;

(f) environmental impact assessment; and

(g) line or equipment upgrades.

(11) A distributor must not connect a facility which the distribution impact assessment studies indicate will have a detrimental effect, exceeding the parameters laid down in the Namibia Quality of Supply and Service Standards, when connected to the network.

(12) A distributor may request the customer to submit design information, drawings or other relevant information to the distributor if the distributor believes any proposed installation or modification has the potential to adversely or materially affect the performance of the distribution power system.

(13) Should the results of the distribution power system impact assessment studies of proposed new or altered equipment owned, operated or controlled by the distributor indicate that there will be a material effect at the point of connection the distributor must notify all affected customers prior to commissioning.

(14) The distributor must provide on request of a customer, design information, drawings or other relevant information of the present or proposed distribution installation.

(15) A distributor must connect an embedded generator in accordance with the requirements of the Connection Code.

(16) A distributor must maintain a database of all embedded generators connected to the distribution power system.

(17) The employees of a distributor or its agents entering the customer premises must comply with the safety requirements of the customer.

Responsibilities of customers and users

11. (1) A customer must provide safe access to the employees of a distributor to carry out the installation, operation and maintenance of the electrical equipment of the distributor on the premises of the customer.

(2) A customer must ensure that during system contingencies there is no unnecessary delay to access to the equipment of the distributor.

(3) A customer must not interfere and must use best endeavours not to allow interference with the distributor's distribution power system including any of the distributor’s equipment installed in or on the customer’s premises.

(4) A customer is responsible for the removal and reinstallation of privately owned equipment for the distributor to perform the installation work that the customer has requested.

(5) A customer other than a customer for domestic supply must -

(a) prior to commissioning, attempt to identify if new or altered equipment owned, operated or controlled by the customer could have a detrimental effect at the point of connection; and

(b) must advise the distributor where a detrimental effect contemplated in subcode 5(a) is identified.

(6) A customer must maintain the clearances to its live equipment in accordance with applicable legislation, relevant standards and prudent electricity practices.

(7) If a customer believes the present or proposed distributor installation has the potential to

adversely or materially affect the performance of the plant of the customer, the customer may request the distributor to submit design information, drawings or other relevant information.

(8) A customer must comply with the reasonable additional requirements specified by the relevant distributor in respect of the technical and design requirements of equipment proposed to be connected to the distribution power system.

(9) A customer must -

(a) not allow a supply of electricity to its electrical installation to be used other than at the customer's premises nor supply electricity to any other person;

(b) not allow electricity supplied to the customer to bypass the meter.

PART 2
DISTRIBUTION POWER SYSTEM TECHNICAL REQUIREMENTS

Protection requirements

12. (1) The protection system of a distributor must be appropriately designed and maintained to ensure -

(a) that the protection system is able to detect an electrical fault within a specific section of the electrical network and to trip only the appropriate or relevant sections of the network in order to clear that fault with minimum disturbance to the rest of the network;

(b) safety and minimum interruptions of supply to customers.

(2) A customer must install and maintain protection, which is compatible with the existing distribution power system protection.

(3) The protection settings of a customer must ensure coordination with the protection of the distributor.

(4) A customer must provide the distributor with test certificates, prior to commissioning, of the protection system that is installed at the point of interface with the distributor.

(5) The protection system of a participant or customer must, where applicable, make provisions to safeguard the equipment of that participant or customer from faults occurring on the distribution power system including loss of one or two phases of the three phase supply, low voltages on the phases and any auto-reclosing or sequential switching features that may exist on the distribution power system.

(6) Where equipment or protection schemes are shared the participants must provide the necessary equipment and interconnections to the equipment of the other party.

(7) The protection system to be considered adequate must perform correctly in terms of reliability, security, speed of operation, selectivity and sensitivity.

(8) All users must ensure correct and appropriate settings of protection to achieve effective isolation of faulty equipment within the specified clearance time.

(9) Protection settings at the point of connection must not be altered, or disconnected without the consultation and agreement of the distributor and the user and in the case where protection is bypassed or disconnected by agreement, then the cause must be rectified and the protection restored to normal condition as quickly as possible.

(10) If agreement has not been reached as contemplated in subcode (9), the electrical equipment must

be removed from service forthwith by the user.

(11) Each user is responsible for tests on its own equipment and a record of test results must be kept for submission upon demand by the distributor or the Board.

(12) The distributor must specify whether embedded generators may remain connected if the section of the distribution power system is isolated from the rest of the network.

(13) The distributor must take reasonable steps to prevent closing circuit breakers onto an islanded network.

(14) For unintentional islanding the embedded generator must comply with the Namibian Embedded Generation Standard.

(15) Embedded generation facilities must be equipped with a dead-line detection protection system to prevent the generator from being connected to a de-energised distribution power system and must comply with the Namibian Embedded Generation Standard.

Quality of supply

13. Distributors, participants and customers must comply with the Namibian Quality of Supply and Quality of Service Standards for at least the following parameters:

(a) voltage harmonics and inter-harmonics;

(b) voltage flicker;

(c) voltage unbalance;

(d) voltage dips;

(e) interruptions of supply;

(f) voltage regulation;

(g) frequency; and

(h) voltage surges and switching disturbances.

Load power factor

14. (1) A customer with a maximum demand meter must ensure that the power factor must not be less than 0.85 lagging and it must not go leading unless otherwise agreed to with the relevant distributor.

(2) If the power factor goes beyond these limits, the customer must take corrective action within a reasonable timeframe to remedy the situation.

(3) A participant or customer intending to install shunt capacitors or other equipment for the purpose of complying with the power factor requirements must obtain the approval of the relevant distributor in writing prior to the installation of that equipment.

Earthing requirements

15. (1) A distributor must advise customers about the neutral earthing methods used in the distribution power system.

(2) The method of neutral earthing used on those portions of installations of a customer that are

physically connected to the distribution power system must comply with the applicable earthing standards of the distributor.

(3) Protective earthing of equipment must be done in accordance with the applicable national standards and reasonable requirements of the distributor.

(4) In cases where the calculated ground potential rise exceeds 5 kV as per Institute of Electrical and Electronic Engineering (IEEE) 80, the responsible party must inform the affected participants.

(5) Minimum lightning protection requirements must be applied to the distribution power system and switching yards.

(6) A distributor must earth the last overhead line tower to the substation switch yard earth.

(7) Substation earthing requirement must be in accordance with recognised international standards, including IEC 60364.

Distribution network interruption performance indices

16. (1) The Board is responsible for setting the indicators to be reported on as part of the distribution reliability indices.

(2) The Board may from time to time change the indicators to be reported on by giving the relevant distributors written notice of the required indicators not less than six months before the start of the distributor fiscal year in which the indicators must be reported on.

(3) Before the end of each fiscal year a distributor must publish its targets for reliability of supply for the following year and as a minimum, unless changed by the Board as provided for in subcode (2), these targets must include -

(a) average total duration of interruptions of supply a customer experiences per year as per SAIDI;

(b) average number of interruptions of supply per customer, as per SAIFI, excluding momentary interruptions of supply; and

(c) average time required to restore electricity supply (CAIDI), using the formula $CAIDI = SAIDI/SAIFI$.

(4) The Board must annually evaluate the distribution power system reliability indices to compare actual performance of each distributor with the unique targets of the distributor set by the distributor and the Board must publish these comparative results.

Losses in distribution power system

17. (1) A loss in the distribution power system must be classified into either a category of -

(a) technical losses;

(b) non-technical losses; or

(c) administrative losses.

(2) The Board must set targets for acceptable levels of the types of losses in consultation with distributors.

(3) Distributors must report annually to the Board on their losses.

(4) The Board must monitor trends in the development of losses for distributors.

Equipment requirements

18. (1) Equipment at the connection point must comply with the -

(a) prescribed standards of the distributor; and

(b) national standards prevailing at the time.

(2) A distributor must provide the customer with the necessary information to enable the customer to install equipment with the required rating and capacity.

(3) A participant must ensure that all equipment at the connection point is maintained at least in accordance with the specifications of the manufacturer or an alternate industry recognised practice.

(4) A participant or customer with demand meters must retain the test results and maintenance records relating to the equipment at the connection point and make this information available if requested.

PART 3
DISTRIBUTION POWER SYSTEM PLANNING AND DEVELOPMENT

Framework for distribution network planning and development

19. (1) A distributor must source relevant data from various sources including the following sources, where available:

(a) National Integrated Resource Plan;

(b) Local Integrated Resource Plan;

(c) Integrated Development Plan;

(d) Rural Electricity Distribution Master Plan;

(e) customer information;

(f) system performance statistics;

(g) distribution network load forecast; and

(h) any other relevant Government and customer development plans,

to establish the need for network strengthening.

(2) A distributor must annually compile a five year load forecast at the incoming points of supply of the distributor including the cross-boundary connections of the distributor.

(3) A distributor must compile network development plans with a minimum window period of five years which plan must consider load and embedded generators and as a minimum include the description, cost, timing and rationale of any planned network strengthening, and any potential impact on customers.

(4) The network development plans contemplated in subcode (3) must be reviewed at least every three years.

(5) The aim of network development plans is to ensure a capable network and may therefore include all relevant activities such as electrification and refurbishment.

(6) The network development plans must be drawn up taking into account only available information and unexpected loads, embedded generation or customer requests can be retrospectively added to the plans.

(7) The network development plans and post release changes must be submitted by the distributor to the Board on request to do so.

(8) The network development plans must be made available to a participant or user on request to do so.

Approach to network investment criteria

20. (1) Distribution tariffs should be sufficient to allow the necessary investments in the networks to be carried out to ensure the long term viability of the networks.

(2) A distributor must invest in the distribution power system when the required development meets the technical and investment criteria specified under code 21.

(3) The need to invest must first be decided by the distributor on technical grounds and an investment must be a technically acceptable solution.

(4) To be a technically acceptable solution as contemplated in subcode (3) the investment must provide for standard supply minimum -

(a) quality requirements in terms of Namibia Quality of Supply and and Quality of Service Standards; and

(b) reliability and operational requirements as determined by this Code and by the Board.

(5) The investment choice must be justified by considering technical alternatives on a least life-cycle cost approach where the least life-cycle cost is the discounted least cost option over the lifetime of the equipment, taking into account the technical alternatives for investment, operating expenses and maintenance.

(6) Calculations to justify investment must assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

(7) The following key economic and financial parameters must be determined by a Board approved process:

(a) discount rate;

(b) customer interruption cost or cost of unserved energy; and

(c) other parameters, such as tariffs and additional economic parameters.

General investment criteria

21. (1) Investments should be justified as a least life-cycle cost solution after taking into account alternatives that consider the following:

(a) the investment that will minimise the cost of the energy supplied and the customer interruption cost;

(b) current and projected demand on the network;

(c) current and projected embedded generation on the network;

(d) reduction of life-cycle costs including reduction of technical losses, operating and maintenance

costs and telecommunication projects;

(e) current condition of assets and refurbishment and maintenance requirements;

(f) demand and supply options; and

(g) any associated risks.

(2) Shared network investments must be evaluated on the least life-cycle cost, where the economic cost will consider the least life-cycle cost of the electricity related investment to both the distributor and the customer.

(3) Investments made by the distributor dedicated to a particular customer must be evaluated on a least life-cycle distributor cost and the distributor cost will consider only the least life-cycle cost to the distributor.

(4) The distributor must evaluate investments in terms of the following categories:

(a) shared network investments;

(b) dedicated customer connections;

(c) statutory investments; and

(d) connections of international customers.

Least economic cost criteria for shared network investments

22. Shared network investments are to be justified on least economic cost and in determining the least economic cost for shared network investments the investment must be justified to minimise the cost to the electricity industry and not just to the distributor.

Least life-cycle cost criteria for customer connections

23. (1) Connection costs and connection charges must be determined by the distributor in accordance with the National Connection Charge Policy and any applicable code.

(2) For standard connections the connection investment must be justified on the technically acceptable least life-cycle costs.

(3) The distributor must refurbish, replace, or reconfigure all equipment in accordance with standard supply criteria at no cost to the customer, and this will be allowed to be recovered through the distribution use of system charges.

Investment criteria for customers requiring a premium connection

24. (1) Where a customer has technical specifications that cause investment above the least life-cycle cost to the distributor, this will be considered a premium connection.

(2) A distributor must investigate these additional requirements and compile a least life-cycle cost solution.

(3) If the customer agrees to the solution, all costs to meet the customer requirement in excess of what is considered the least life-cycle cost standard connection investment are payable as a premium connection charge by the customer.

(4) The costs contemplated in subcode (3) must be appropriately prorated, if a portion of the investment can be justified based on improved reliability or reduction of costs to the distributor.

(5) Investment costs for the refurbishment or replacement of identified premium connection assets, at the time when the equipment is no longer reliable or safe for operations, must be evaluated using the least economic cost solution.

(6) Refurbishment costs for premium supplies in excess of least economic cost are payable by the customer through a new premium connection charge and may not be recovered through distribution use of system (network) charges.

(7) The least economic cost for refurbishment or replacement of premium assets must be considered as the least life-cycle cost for the distributor required to provide a standard supply plus, if applicable, the estimated cost to the customer to change any of the equipment of the customer to comply with the refurbishment or replacement of the asset using the least life-cycle cost solution.

Statutory or strategic investments

25. (1) A distributor must make strategic and statutory investments as contemplated in subcode (3).

(2) Statutory and strategic investments must be motivated on a least economic cost basis as contemplated in code 21.

(3) Strategic and statutory projects include the following:

(a) investments formally requested in terms of published government policy but not considered customer dedicated assets;

(b) projects necessary to meet environmental legislation including the construction of oil containment dams;

(c) expenditure to satisfy the requirements on the distributor to comply with its licence conditions and safety legislation;

(d) possible compulsory contractual commitments; and

(e) servitude acquisition.

Investment criteria for connections of international customers

26. The investment for international customers must be in terms of the criteria set out for a dedicated connection, but the distributor must charge a connection charge that ensures that there is no cross border subsidy.

Excluded services

27. (1) Excluded services may be competitive or provided by the distributor as a monopoly service.

(2) Monopoly services are those mandatory services to ensure a standard of work that meets quality of supply, reliability and safety standards.

(3) Excluded services include the following:

(a) design and construction of dedicated customer connections;

(b) recoverable works such as inspection and maintenance of non-distributor owned installations, line relocation and other requested recoverable works; and

(c) the construction and maintenance of public lighting assets.

(4) For excluded services, customers may choose a contractor other than the distributor, provided that an agreement is reached between the distributor and the customer prior to the project being undertaken detailing the conditions.

(5) The conditions contemplated in subcode (4) must set out -

(a) the assets the customer may work on or not work on;

(b) the terms and conditions for the approval of the network design;

(c) the terms and conditions for the inspection and the work done prior to any agreement to take over and commission the supply;

(d) the charges to be raised by the distributor for monopoly related services; and

(6) the fees charged by the distributor for excluded services.

CHAPTER 3
DISTRIBUTION POWER SYSTEM OPERATIONS

PART 1
OPERATIONAL RELATIONS, PROCEDURES, PLANNING, CONDITIONS AND CONTROL

Operational responsibilities of distributors

28. (1) The distributor must operate the distribution power system to achieve the highest degree of reliability practicable and appropriate remedial action must be taken promptly to relieve any abnormal operating condition that may jeopardise reliable operation.

(2) The distributor must co-ordinate voltage control, operating on the distribution power system and security monitoring on a system-wide basis in order to ensure safe, reliable and economic operation of the distribution power system.

(3) In the event of an embedded generator having to shut-down or island its plant because of a disturbance on the distribution power system, the distributor must carry out network restoration to minimise the time required to resynchronise the shed embedded generating units.

(4) The distributor may shed customer load to maintain system integrity and the distributor must restore customer load as soon as possible with due consideration of the possibility of cascading failure or operating at abnormally low frequency or voltage for an extended period of time.

(5) The distributor must operate the distribution power system in such a way as to minimise adverse effects of disturbances on customers.

(6) The distributor must operate the distribution power system as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe double contingency.

(7) Multiple distribution outages of a credible nature must be examined and, whenever practical, the distributor must operate the distribution power system to protect it against instability, uncontrolled separation and cascading outages.

(8) The distributor is responsible for efficient restoration of the distribution power system after

interruptions of supply.

(9) The distributor must operate and maintain primary and emergency control centres and facilities to ensure continuous operation of the distribution power system.

(10) The distributor must -

(a) establish and implement operating instructions, procedures, standards and guidelines to cover the operation of the distribution power system under normal and abnormal system conditions; and

(b) maintain a database with version control of all the documents, relating to the establishment and implementation contemplated in subcode 10(a), which are in compliance with licence conditions.

(11) The distributor must operate the distribution power system, as far as reasonably possible, within defined technical standards and equipment ratings.

(12) The distributor must manage constraints on the distribution power system through the determination of operational limits.

(13) To achieve a high degree of service reliability the distributor must ensure adequate and reliable communications between control centres, embedded generators and substations.

(14) The distributor is responsible for the ongoing determination of the distribution power system protection philosophy, as contrasted to equipment protection.

(15) The distributor must determine and review on a regular basis the relay settings for main and backup protection on the distribution power system.

(16) The distributor must develop and publish procedures for load shedding.

(17) The distributor must ensure adequate and reliable communications to all major users of the distribution power system.

Operational responsibilities of embedded generators and customers

29. (1) When conditions on the distribution power system under normal or abnormal conditions may jeopardise plant or personnel of customers, customers must immediately disconnect from the distribution power system.

(2) The embedded generator must ensure that its generating unit is operated within the capabilities defined in the connection agreement entered into with the distributor.

(3) The embedded generator is responsible for the provision of the operational information contemplated in Part 2 of Chapter 54.

(4) The embedded generator must reasonably cooperate with the distributor in executing all the operational activities during an emergency generation condition.

(5) Customers must assist the distributor in correcting quality of supply problems caused by the equipment of a customer connected to the distribution power system.

(6) Customers must ensure that their equipment connected to the distribution power system does not cause any degradation or operational adversity to the distribution power system.

(7) Customers must operate their equipment so as to ensure that they comply with the conditions

specified in their connection agreements.

(8) Customers must -

(a) declare any co-generating plant whether licensed or not; and

(b) specify the interlocking mechanism, to prevent inadvertent parallel operation with the distribution power system or any infeed while the distribution power system is deenergised.

Operational authority

30. (1) The distributor has the authority to instruct operating on the distribution power system but operational authority for other networks must lie with the respective asset operator.

(2) Network control, as it affects the interface between the distributor and a customer, must be in accordance with the operating agreements between the participants.

(3) A participant may not operate the equipment of another participant without the permission of that other participant.

(4) Despite subcode (3), the asset owner has the right to test a participant who intends to operate the equipment of another participant before permitting that participant to operate that equipment.

Operating procedures

31. (1) The distributor must develop and maintain operating procedures for the safe operating of the distribution power system and for assets connected to the distribution power system.

(2) The operating procedures contemplated in subcode (1) must be adhered to by participants when operating equipment on the distribution power system or connected to the distribution power system.

(3) A customer must -

(a) have safety rules and procedures; and

(b) ensure that safety rules and procedures contemplated in subcode 3(a), comply with the law and the Namibia Electricity Safety Code, 2009.

(4) Customers must ensure that the rules and procedures contemplated in subcode (3) are compatible with the operating procedures contemplated in subcode (1).

(5) Customers and licensees must enter into operating agreements as set out in the licence conditions of licensees.

(6) For standard customers the operating agreements contemplated in subcode (5) may form part of the connection agreement or general conditions of supply.

Operational liaison

32. (1) The participants -

(a) are responsible for the nomination of personnel with sufficient expertise to operate the distribution power system; and

(b) must establish direct communication channels amongst themselves to ensure the flow of information exchange between the participants.

(2) If a participant experiences an emergency that participant must notify other participants and -

(a) the other participants must assist to the extent necessary to ensure that the emergency does not jeopardise the operation of the distribution power system or health of plant; and

(b) that participant must ensure that the emergency notification contains sufficient details in describing the event including the cause, timing and recording of the event to assist the recipient in assessing the risk and implications to the distribution power system or the equipment of the customer.

(3) For planned events which may have an operational effect on the distribution power system or on the equipment of a customer connected to the distribution power system, the participants must notify each other on whose equipment the operational event may have an effect.

(4) In the event that it is physically possible for a customer or embedded generators to transfer load from one point of supply to another by performing switching operations on the network of a customer the operating agreement must cover at least the operational communication and notice period requirements and switching procedures for such load transfers.

(5) The embedded generator must in consultation with a specific distributor compile both a comprehensive maintenance philosophy and a test and inspection plan for all equipment, systems and protection schemes installed at the connection point addressing concerns from both parties.

(6) The distributor and customers must agree on the busbar configuration at each point of supply during normal and emergency conditions and the details of the configuration must be included in the operating agreement between the participants.

Emergency and contingency planning

33. (1) The distributor must develop and maintain a distribution power system emergency procedures manual to manage the system contingencies and emergencies that are relevant to the performance of the distribution power system and the interconnected power system.

(2) A contingency plan contemplated in subcode (1) must be developed in consultation with all participants and must be consistent with internationally acceptable utility practices and must include -

(a) under-frequency load shedding;

(b) prevention of voltage slide and collapse;

(c) meeting national disaster management requirements including the necessary minimum load requirements;

(d) forced outages at all points of interface; and

(e) supply restoration.

(3) Emergency plans must allow for safe and orderly recovery from a partial or complete system collapse, with minimum impact on customers.

(4) Contingency or emergency plans must be periodically tested with simulations or other approved methodologies and the results must be appropriately documented.

(5) If the tests contemplated in subcode (4) cause undue risk or undue cost to a participant, the distributor must take that risk or cost into consideration when deciding whether to conduct the test.

(6) The tests contemplated in subcode (3) must be carried out at a time that is least disruptive to the participants and the costs of the tests must be paid for by the respective asset owners.

(7) The distributor must ensure the co-ordination of the tests contemplated in subcode (3) in consultation with all affected participants.

(8) The distributor must, in consultation with the transmission licensee and system operator, set the requirements and implement:

(a) automatic and manual under frequency load shedding in accordance with the requirements of the system operator;

(b) automatic and manual under voltage load shedding to prevent voltage collapse; and

(c) manual load shedding to maintain network integrity.

(9) Participants must make available loads and schemes to comply with these requirements.

(10) The distributor is responsible for -

(a) determining emergency operational limits on the distribution power system;

(b) updating the emergency operational limits contemplated in subcode 10(a) periodically; and

(c) making the emergency operational limits contemplated in subcode 10(a) available to the participants.

(11) The distributor must conduct network studies which may include but not be limited to load flow, fault level, stability and resonance studies to determine the effect that various component failures would have on the reliability of the distribution power system.

Operation during abnormal operating conditions

34. (1) Operation under abnormal operating conditions must comprise all conditions deviating from normal operating conditions.

(2) During abnormal operating conditions the distributor must be obliged to take necessary precautionary measures to prevent network disturbance from spreading and to restore supply to customers.

(3) The distributor must cooperate with the transmission licensee in taking corrective measures in the event of abnormal operating conditions on the distribution power system.

(4) The corrective measures must include both supply-side and demand-side options and where possible warnings must be issued by the distributor to potentially affected participants on expected utilisation of any contingency resources.

(5) The distributor may disrupt some sections of the network in the event of a prolonged disturbance resulting from unsuccessful corrective measures undertaken.

(6) The distributor must ensure that termination of the use of emergency resources occurs with the order of return being determined by the most critical loads, first in terms of safety and then plant.

(7) During emergencies that require load shedding, the request to shed load must be initiated in accordance with agreed procedures prepared and published by the distributor.

Independent action by participants

35. (1) A participant has the right to reduce supply or demand or disconnect a point of connection under emergency conditions if the reducing of supply or demand or the disconnection of a point of connection is necessary for the protection of life or equipment.

(2) A participant must give advance notice of the action contemplated in subcode (1) to the distributor and other affected participants if possible for, amongst other emergency conditions, hot connections, solid breakers and malfunctioning protection.

(3) During customer emergencies that require load shedding, a request to shed load issued by the distributor must be initiated in accordance with agreed procedures prepared and published by the distributor.

Demand and voltage control

36. (1) The distributor must implement demand control measures when -

(a) instructed to do so by the system operator;

(b) abnormal operating conditions exist on the distribution power system;

(c) multiple outage contingency exists resulting in island grid operation; or

(d) any other operational event exists which the distributor considers to warrant the implementation of demand control measures for the safe operation of the distribution power system.

(2) Demand control must include but is not limited to -

(a) customer demand management;

(b) customer disconnection;

(c) automatic low frequency disconnection;

(d) emergency manual disconnection;

(e) voluntary load curtailment;

(f) manual load dropping; and

(g) deploying energy storage capacity, if available.

(3) The distributor must develop load reduction procedures to reduce load in a controlled manner by reducing or disconnecting certain customer loads.

(4) The distributor must coordinate all the demand control measures undertaken with affected customers.

(5) Distribution power system voltages must be controlled during normal operation to be at least within statutory limits at the points of supply and otherwise as agreed with customers.

(6) The distributor is responsible for maintaining reactive power management including all facilities for reactive power compensation on the distribution power system and the other connected generating units to ensure compliance with the agreed specified limits, operational voltage parameters and power factor parameters.

Fault reporting and analysis or incident investigation

37. (1) The distributor and consumers must report the loss of major loads (>2.5MW) to the transmission system operator within 15 minutes of the event occurring and warning of the reconnection of the loads must similarly be given with at least 15 minutes advance notice.

(2) The participants must report to the control centre of the distributor or appointed person all major incidents occurring on the participants' installation or incidents occurring on the distribution power system that would potentially affect the overall performance and reliability of the distribution power system including but not limited to -

(a) voltage or frequency outside statutory limits;

(b) deviations from load drawn from the distribution power system; or

(c) major breakdowns of equipment supplying power to the customers.

(3) Despite subcode (2) the distributor must -

(a) investigate any incident that materially affected the quality of the service to another participant including interruptions of supply, disconnections, under or over voltage or frequency incidents and quality of supply contraventions;

(b) avail a preliminary incident report after three working days and a final report within three months; and

(c) initiate and co-ordinate the investigation contemplated in subcode 3(a) and arrange for the writing of the report contemplated in subcode 3(b) and involve all affected participants.

(4) The participants contemplated in subcode (3)(c) must make all relevant information available to the distributor and participate where reasonably required and the distributor must make the report contemplated in subcode (3)(b) available to any requesting participant within the confidentiality constraints.

(5) The report contemplated in subcode (3)(b) must include, at a minimum, the -

(a) date and time of the incident;

(b) location of the incident;

(c) duration of the incident;

(d) equipment involved;

(e) description of the incident;

(f) demand control measures undertaken;

(g) embedded generation interrupted;

(h) frequency response achieved;

(i) estimated date and time of return to normal service;

(j) customer load tripped in MW and energy lost when incident occurred or as a direct result of incident not including any demand control measures taken; and

(k) estimated number of customers having lost supply.

(6) A participant may request an independent audit of the report contemplated in subcode (3)(b) at own cost and, if the audit findings disagree with the report, the participant may follow the dispute resolution mechanism but if the audit findings agree with the report the report recommendations must stand.

(7) Recommendations that require a change in the Distribution Grid Code must -

(a) be submitted to the review process contemplated in codes 10, 11 and 12 of the Transmission Grid Code; and

(b) only be implemented upon approval of the amendment.

(8) All other recommendations must be implemented by the participant within a time frame of -

(a) three working days for the preliminary incident report under subcode (3)(b); and

(b) three months for the final report under subcode (3)(b).

Distributor maintenance program

38. (1) A distributor must have a maintenance philosophy against which their maintenance practices and programs are compiled and documented in accordance with prudent electricity practices and any rules, standards or guidelines of the Board that may apply.

(2) The documented maintenance programs contemplated in subcode (1) must be auditable.

(3) The distributor must compile an annual maintenance plan in line with the budget period and provide for sufficient budget to execute that plan.

(4) Accurate records of maintenance done must be kept for a period of five years.

(5) Scheduling of planned outages must coincide with the maintenance requirements of other participants connected to the affected network.

(6) A distributor must, at least five days in advance of a planned outage, inform participants that may be affected by that planned outage.

Testing and monitoring

39. (1) The distributor has the right to test and monitor any equipment or customer installation connected to the distribution power system to ensure that the customers are not operating outside the technical parameters specified in any part of the this Code and other applicable standards which the customers are required to comply with.

(2) Despite subcode (1), the distributor must inform the customer about any routine test and monitoring the distributor intends to undertake on the installation of the customer.

(3) A customer found to be operating outside the technical parameters must within such time agreed upon by the participants involved remedy the situation or disconnect from its network the equipment causing problems.

Safety coordination

40. (1) The distributor must in accordance with the relevant legislation governing health and safety in the workplace establish health and safety management guidelines to ensure the health and safety of personnel working on the distribution power system or any equipment connected to the distribution power system.

(2) The health and safety management guidelines contemplated in subcode (1) must have a set of rules and instructions for implementing safety precautions on medium voltage and high voltage equipment and the participants must adopt these rules and any work done on the distribution power system or on the installation of the customer must be governed by these rules.

(3) Despite subcode (2), the health and safety management guidelines must contain details of, but not be limited to -

(a) safety coordination procedures;

(b) appointment of safety coordinators or authorised safety personnel;

(c) safety logs and record of safety precautions;

(d) location of safety precautions;

(e) implementation of safety precautions;

(f) environmental safety issues; and

(g) documentation control.

(4) The participants must coordinate the appointment of safety personnel and must agree on the duties to be carried by the appointed persons.

Disconnection and reconnection

41. (1) The distributor may disconnect supply to the supply address of the customer if the customer fails to comply with the written notice of non-compliance issued by the distributor or any arrangement entered into by the distributor and the customer which the customer has failed to comply with including non-compliance with the applicable standards of the distributor.

(2) The distributor may interrupt or disconnect supply if a threat of injury or material damage is anticipated as a result of the malfunctioning of the electrical installation equipment on the premises of the customer or on the distribution power system which may result in any of the following:

(a) planned or unplanned maintenance on the distribution power system or customers installation;

(b) load shedding;

(c) installation of new supply or restoration of supply to other customers; or

(d) instruction from the transmission licensee.

(3) The distributor may disconnect immediately without notice the supply to the supply address of the customer if:

(a) the supply of electricity to a customer is used anywhere else other than at the premises of the customer as specified in the connection agreement;

(b) a customer takes, at the supply address of the customer, electricity supplied to another customer;

(c) a customer tampers with or permits tampering with the meter and associated components;

(d) a customer causes or allows electricity supply to the supply address of the customer to bypass the meter.

(4) A customer, with demand meter, must give written notice to the distributor of any intended voluntary disconnection.

(5) The distributor must reconnect supply to the customer on request by the customer or supply licensee on behalf of the customer subject to compliance with the relevant provisions of this Code and other distributor applicable standards including the timing of reconnection and any reconnection charge imposed by the distributor.

Commissioning

42. (1) All aspects of commissioning, by participants, of new equipment associated with the distribution power system connection, or re-commissioning of such existing equipment, must be agreed in writing with the distributor, acting reasonably, before such commissioning starts.

(2) The said aspects must include, but not be limited to the following:

(a) commissioning procedures and programmes;

(b) documents and drawings required;

(c) proof of compliance with standards;

(d) documentary proof of the completion of all required tests;

(e) SCADA information, to be available and tested before commissioning; and

(f) site responsibilities and authorities.

(3) Participants must give minimum notice of one month, unless otherwise agreed, from the date of receipt of the request for all commissioning or re-commissioning.

(4) Where commissioning is likely to involve a requirement for dispatch or operating for test purposes, the participant must notify the distributor of that requirement and of reasonable details as to the duration and type of testing required.

(5) When commissioning equipment at the point of connection, the distributor must liaise with the affected participants on all aspects that could potentially affect the participants' operation.

(6) The distributor and participants must perform all commissioning tests required in order to confirm that the plant and equipment, of that distributor and the participants, meet all the requirements of the Distribution Grid Code that have to be met before going on-line.

(7) Embedded generators must perform tests in accordance with the Connection Code.

PART 2
MAINTENANCE COORDINATION, OUTAGE PLANNING AND COMMUNICATION AND CONTROL

Responsibilities of distributor

43. (1) The distributor must, with reference to the outage plans of the relevant network service provider and the outage plans of the relevant generator, compile the daily outage schedule which must -

(a) endeavour to cater for the planned maintenance and commissioning of new equipment;

(b) describe the planned outage;

(c) identify the risks and impact on network performance in accordance with the relevant quality of supply and service standard;

(d) describe the practical contingency plans devised to counter risks; and

(e) define the roles and responsibilities of the personnel designated to manage and minimise the impact of these outages on the distribution power system and its users.

(2) The distributor must co-ordinate relevant outages with the system operator.

(3) The distributor may require from the customers information regarding major plant and associated equipment which may affect the performance of the distribution power system and may require additional resources to be committed during the outage planning process.

(4) Customers with own generation and embedded generators with a capacity greater than 1 MW must furnish to the distributor information on planned outages in order for the distributor to properly plan, and coordinate its control, maintenance and operation activities.

(5) The distribution outage plans must be adjusted to coordinate with the transmission outage plan which must further be coordinated with the generation outage plan.

(6) The distributor, transmission licensee and generation services must meet regularly on dates agreed upon by the participants to revise, discuss and produce a coordinated outage plan.

(7) The distribution outage plan must be submitted to the Board upon request.

Risk-related outages

44. (1) All risk-related outages must be scheduled with an executable contingency plan in place and the compilation of the contingency plan is the responsibility of the relevant distributor.

(2) A contingency plan contemplated in subcode (1) must address the -

(a) safety of personnel;

(b) security and rating of equipment; and

(c) continuity of supply.

(3) The relevant control centres must confirm that it is possible to execute the contingency plan contemplated in subcode (1) successfully.

Refusal or cancellation of outages

45. (1) A participant may not unreasonably refuse or cancel a confirmed outage and a participant may not unreasonably postpone or cancel a previously accepted outage.

(2) The direct costs related to the cancellation or postponement of an outage must be borne by the respective asset owners.

Communication of system conditions, operational information and distribution power system performance

46. (1) The distributor is responsible for providing participants with operational information as may be agreed which must include information regarding planned and forced outages on the distributor.

(2) The distributor must inform participants of any network condition that is likely to impact the

short and long-term operation of that participant.

(3) The distributor must -

(a) record the operational information as specified in code 66; and

(b) avail the information recorded as contemplated in subcode 3(a) to a participant if the participant requests for that information.

Unplanned interruptions of supply or outages

47. (1) In case of unplanned interruptions of supply or outages the distributor may require a customer to comply with reasonable and appropriate instructions from the distributor and may further -

(a) require the customer to provide the distributor emergency access to customer owned distribution equipment normally operated by the distributor or distributor owned equipment on the property of the customer;

(b) interrupt supply to the customer to effect repairs to the distribution power system; and

(c) require customers with permanently connected back up facilities to notify the distributor regarding the presence of such equipment.

(2) The distributor must make arrangements to notify the participants about the expected duration and other details of the unplanned interruptions of supply contemplated in subcode (1).

Planned interruptions of supply or outages

48. For planned interruptions of supply or outages, the distributor must provide the affected customers with information relating to the expected date of the outage, time and duration of the outage and must establish reasonable means of communication to the customers for outage related enquiries.

Communication and control

49. Where communication and control facilities are shared between the distributor and other participants, the distributor must ensure that operating procedures are established in consultation with the participants.

CHAPTER 4
DISTRIBUTION POWER SYSTEM METERING

Principles of distribution metering

50. (1) The following points must have a metering installation -

(a) each point of supply connecting a consumer to the distribution power system;

(b) each point of connection between a generator and the distribution power system; and

(c) each point connecting the distribution power systems of Namibia to a neighbouring country.

(2) The type of metering installation at each metering point as contemplated in subcode (1) must comply with the NRS 057 metering specifications.

(3) Customers with a maximum demand of 5 MVA or more and generators and connections to neighbouring countries must have main and check metering and there must be separate main and check CT cores but one dedicated VT must be allowed.

(4) A metering point may be located at a point other than the point of connection or the point of supply by mutual agreement between the participants.

(5) Customers may request the installation of their own separate check meters and any extra costs must be paid for by the requesting customer and the distributor must install and control the check meters.

(6) For a customer wishing to connect an embedded generator to the distribution power system -

(a) the installation must not be metered using a pre-paid meter;

(b) the installation must have a meter capable of measuring active power flow in both directions;

(c) unless the distributor has a small scale feed-in tariff approved by the Board the energy supplied by the customer into the distribution power system must be compensated by the distributor at the avoided cost rate of the distributor; and

(d) the installation must, where applicable, comply with net metering rules made by the Board under the Act.

Responsibility for metering installations

51. (1) For the purposes of this Code, the distributor must be the owner of the meter and metering installation.

(2) Metering equipment owned by the distributor, supply licensee or metering service provider but installed on the premises of the customer remains the property of the distributor.

(3) Except with written consent by the distributor, access by customers or customer representatives to meters, metering circuits and metering data must be restricted to ensure that the integrity of the metering device, metering installation and meter data are not at risk.

(4) Unless prior written approval has been obtained customers or customer representatives may not have direct physical access to meters including access gained by downloading the metering information from the meter directly through the digital communication interface or remotely through any communication media such as a modem.

(5) Despite subcode (4) requests from customers to read their own meters must not be unreasonably refused.

(6) Except with written consent by the distributor, customers or customer representatives may not install any metering or other equipment integrated into the distributor's CT and VT metering circuits, test blocks, terminals or any portion forming part of the electrical metering installation.

(7) A customer on whose premises metering equipment is installed which is owned and operated by the distributor, metering service provider or supply licensee must provide reasonable access to the metering equipment but an official identification must be produced on request.

(8) Where a metering installation is situated in a restricted area the procedures stated in NRS057, applicable legislation or agreed on by the parties must be followed to gain access to the equipment.

(9) If a customer or the customer's representative requires real time energy pulses (kWh & kVArh) at a metering installation, the distributor must provide the real-time energy pulses through mutual agreement and the customer must pay the costs of installation in that event.

(10) Any changes that may affect the authorised and safe access of the parties to the metering equipment must be reported as soon as it is brought to the attention any of the parties.

(11) Customers may not tamper or permit tampering with metering equipment owned by the distributor.

(12) The distributor is responsible for ensuring that all points identified as metering points in accordance with the principles of the previous sections have metering installations.

(13) The distributor is responsible for managing and collecting metering information.

(14) Participants connected to or wanting to connect to the distribution power system must provide the distributor with all information considered necessary to enable performance of its metering duties.

(15) In the event of a metering installation being positioned between two distributors -

(a) both distributors are responsible for installing and maintaining the metering installation in accordance with the requirements of this Code;

(b) all costs related to the metering installation must be paid for by both distributors; and

(c) the distributors must ensure that the transmission metering administrator is given remote or electronic access to the metering installation where appropriate and if access to the metering installation compromises the security of the installation, then metering data must be supplied to the transmission metering administrator on a daily basis in an appropriate format if required.

Metering installation components

52. (1) The following principles apply to all metering installations for customers with a maximum demand of 5 MVA or more and to generators and connections to neighbouring countries:

(a) the meter or recorder must be able to store data in memory for 35 days or more;

(b) data stored in either a meter or a recorder must be remotely and locally retrievable;

(c) a meter must be remotely interrogated on a daily basis where possible or as mutually agreed by the affected participants;

(d) a meter must be visible and accessible, but the access must be restricted to only persons authorised by the distributor;

(e) data for customers must be historical data situated on a secure server and when required by a customer metering impulses must be provided by a distributor to the customer;

(f) a telecommunications medium must be connected to the meter or recorder contemplated in subcode 1(a) where possible; and

(g) the meter data retrieval process must be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories.

(2) The following principles apply to all metering installations:

(a) the accuracy of meters and recorders must be in accordance with the minimum requirements of NRS 057-2;

(b) commissioning of the metering installation and metering data supporting systems must take place in accordance with the requirements of NRS 057;

(c) both active and reactive energy must be measurable without compromising any requirements of this code where applicable;

(d) the meters must measure both active and reactive energy flow in both directions where applicable; and

(e) the meters must be configured to store or record metering data in half-hourly integration periods.

(3) If a metering installation is used for purposes other than metering data -

(a) the use must not in any way obstruct metering data collection and accuracy requirements;

(b) the secondary use must be communicated to all participants who may be affected by the secondary use of the installation; and

(c) no secondary user must interfere with VT or CT circuitry.

(4) Metering installations must be audited in accordance with NRS 057 or equivalent.

Data validation

53. (1) Data validation must be carried out in accordance with NRS 057.

(2) In the event of -

(a) electronic access to the meters not being possible;

(b) an emergency bypass or other schemes having no metering system; or

(c) metering data not being available, the distributor may resort to -

(i) manual meter data downloading;

(ii) estimation or substitution subject to mutual agreement between the affected parties;

(iii) profiling; or

(iv) reading of the meter at scheduled intervals.

(3) In the event of an estimation having to be made -

(a) a monthly report must be produced for all estimations made; and

(b) the estimation may not be made on three or more consecutive time slots but if that estimation is made the distributor must ensure that the meters are downloaded for the billing cycle.

(4) Not more than 10 slots may be estimated per meter point per month but if that estimation is made the distributor must ensure that the meters are downloaded for the billing cycle.

Data verification

54. In addition to the NRS 057 verification requirements meter readings must be compared with the metering data base at least once a year.

Metering database

55. (1) The distributor must create, maintain and administer a metering database containing the following information:

(a) name and unique identifier of the metering installation;

(b) the date on which the metering installation was commissioned;

(c) the connecting parties at the metering installation;

(d) maintenance history schedules for each metering installation;

(e) telephone numbers used to retrieve information from the metering installation;

(f) type and form of the meter at the metering installation;

(g) fault history of a metering installation; and

(h) commissioning documents for all metering installations.

(2) Information relating to raw and official values as indicated in Section 5.3 of the NRS 057-4 must form part of the metering database and must be retained for at least five years for audit trail purposes.

Testing of metering installations

56. (1) Commissioning, auditing and testing of metering installations must be done in accordance with the NRS 057-4 specification.

(2) A participant may request the Board that testing of a metering installation be performed and that request may not be unreasonably refused but the costs of the testing must be for the account of -

(a) the requesting participant if the meter is found to be accurate; or

(b) the account of the distributor if the meter is found to be inaccurate.

Metering database inconsistencies

57. In the event of testing revealing that data in the metering database is inconsistent with the data in the meter, the distributor must inform all affected participants and corrections must be made to the official metering data and the associated billing to an extent as reasonably agreed between the parties.

Access to metering data

58. (1) Metering data must be accessed through a central database that stores all customer information and is maintained by the distributor.

(2) The distributor must control access to all metering installations.

(3) Electronic access to the meters may not be granted to the customer or any other party unless special permission has been granted by the Board.

(4) Schedules for accessing metering data from the central database must be administered by the distributor in line with NRS 057-4.

(5) All security requirements for metering data must be as specified in NRS 057.

(6) Official metering data must be made available by the licensee on request by the customer in a format agreed on by the parties and the distributor may levy a charge for the provision of that data which is in relation to the cost of providing the data.

Confidentiality

59. (1) Metering data and passwords are confidential information.

CHAPTER 5
DISTRIBUTION POWER SYSTEM INFORMATION EXCHANGE

PART 1
INFORMATION EXCHANGE INTERFACE AND PROVISION AND EXCHANGE OF INFORMATION DURING PLANNING AND CONNECTION PROCESS

Information exchange interface

60. (1) The parties must identify the following for each type of information exchange:

(a) the names and contact details of the persons designated by the information owner as responsible for the provision of information;

(b) the names and contact details of the parties represented by persons requesting the information; and

(c) the purpose for which the information is required.

(2) The parties must agree on appropriate procedures for the transfer of information.

(3) Participants with demand meters must exchange information, prior to commissioning, of new or altered equipment connected at the point of connection or changes to the operational regimes that could have an adverse effect on the distribution power system to enable proper modifications to any affected participants networks and related systems.

Provision and exchange of information during planning and connection process

61. (1) Each distributor must have a supply application form which must request at minimum the information stipulated in this Code.

(2) Customers requesting supply at low voltage must provide the distributor with the information relating to:

(a) new or change in connected loads;

(b) type of load to be connected to the distribution power system;

(c) requested connection date;

(d) requested supply capacity in ampere or kVA and number of phases; and

(e) proposed network connection point address.

(3) Customers requesting supply at medium or high voltage must in addition to the information exchange contemplated in code 60 provide the distributor with the following information:

(a) requested supply voltage;

(b) expected or projected maximum demand (in kVA);

(c) expected load power factor;

(d) switched customer capacitor banks and reactors, which could affect the distribution power system;

(e) whether the load is capable of producing harmonics as specified by equipment manufacturers;

(f) whether there is a harmonic filter and the filters characteristics;

(g) the nature and type of process the supply is requested for;

(h) minimum required fault levels;

(i) start-up requirements; and

(j) whether the customer has any standby generator.

(4) The distributor may request customers to provide information on the proposed installation of the customer and equipment at the point of connection.

(5) Participants must exchange information relating to the protection of distribution power system and customer equipment protection coordination at the point of connection.

(6) Upon any reasonable request the distributor must provide customers or potential customers with any relevant information that they require to properly plan and design their own networks or installations which may include but not limited to:

(a) nominal voltage at which connection will be made;

(b) method of connection, extension and reinforcement details;

(c) the maximum and minimum fault levels;

(d) method of earthing;

(e) maximum installed capacity at the point of supply;

(f) specification of any accommodation of equipment requirement;

(g) individual customer limits relating to:

(i) harmonic distortion;

(ii) voltage flicker;

(iii) voltage unbalance;

(h) expected lead time of providing connection, following formal acceptance of terms for supply;

(i) an indication of network single contingency capability;

(j) an indication of current network performance and power quality;

(k) cost of connection; and

(l) range of current approved tariff structures.

PART 2
OPERATIONAL AND CONFIDENTIALITY INFORMATION

Commissioning and notification

62. (1) Customers must confirm that all information given in the application for supply and additional information subsequently requested by the distributor are correct before the commissioning.

(2) The commissioning dates must be negotiated between the parties.

(3) Participants must agree on the type of operational data to be submitted prior to commissioning which must include test and commissioning report.

(4) A distributor or customer who is the asset owner must -

(a) ensure that all equipment records that affect the integrity of the distribution power system or relevant to the interconnection are maintained for reference for the duration of the operational life of the plant; and

(b) on request from the distributor, make information available within a reasonable time.

(5) The distributor must indicate to the customer what information is relevant in terms of this code.

Sharing of assets and resources

63. Distributors sharing assets and resources must enter into agreements for the provision and sharing of their assets, resources, services and information.

Additional information requirements

64. (1) Should one participant, acting reasonably, determine that additional measurements or indications are needed in relation to another participant's plant and equipment, that participant must consult with the affected participant to agree on the manner in which the need may be met.

(2) The costs related to the modifications for the additional measurements or indications must be for the account of the causal participant.

Communication and liaison

65. (1) Participants must establish a communication channel for exchange of information required for distribution operations which may include the installation of SCADA equipment of the distributor at the customer or installation of the distributor to facilitate the flow of information and data to and from the distribution or transmission control facilities.

(2) A participant -

(a) must designate a person with delegated authority to perform the duties of information owner in respect of the granting of access to information covered in this code to third parties; and

(b) may designate more than one person to perform the duties contemplated in subcode 2(a).

(3) The distributor must take reasonable steps to exchange information with the affected customers of a distributor for distribution and transmission system outages.

(4) Customers must exchange information with the distributor within an agreed lead time on all operations on their installations which may have an adverse effect on the distribution power system including

any planned activities such as plant shutdown or scheduled maintenance.

(5) The communication facilities standards must be set and documented by the distributor.

(6) Any changes to communication facilities standards impacting on participant equipment must be brought to the attention of the participant well in advance of the proposed change.

(7) Any back up or emergency communication channels established by the distributor and deemed necessary for the safe operation of the distribution power system must be agreed upon by the distributor and the participant affected.

(8) All telecommunications shall meet the cyber security requirements as defined in codes 68 and 69.

Data storage and archiving

66. (1) An information owner must store and archive data.

(2) The systems that store the data to be used by the parties must be of their own choice and for their own cost.

(3) All data storage systems must -

(a) be able to be audited by the Board; and

(b) provide for clear and accessible audit trails on all relevant operational transactions.

(4) All requests that require an audit on a system must be undertaken with reasonable notice to the parties.

(5) The information owner must keep all information, except voice recorded information, in its original format for a period of at least five years, unless otherwise specified in this Code, commencing from the date the information was created.

(6) Parties must ensure reasonable security against unauthorised access, use and loss of information for the systems that contain the information.

(7) Distributors must -

(a) use a voice recorder for historical recording of all operational voice communication with participants which must be available for at least three months except where there is an incident involved in which case the requirements of any applicable legislation must apply; and

(b) make the voice records of an identified incident in dispute available within a reasonable time period after a request to do so from a participant or the Board.

(8) Customers with their own medium or high voltage networks must keep proper written or voice recorded records of all operations on their medium and high voltage networks.

(9) An audit trail of all changes made to archived data must -

(a) be maintained;

(b) identify every change made and the time and date of the change; and

(c) include both pre and post values of all content and structure changes.

Confidentiality of information

67. (1) Information exchanged between parties governed by this Code is confidential unless otherwise stated.

(2) Parties receiving information must use the information only for the purpose for which it was supplied.

(3) The information owner may request the receiver of information to enter into a confidentiality agreement before information established to be confidential is provided.

(4) A sample agreement for purposes contemplated in subcode (3) is annexed to this Code as Annexure 1.

(5) Confidential information may not be transferred to a third party without the written consent of the information owner.

(6) Parties must observe the proprietary rights of third parties for the purposes of this Code but access to confidential information within the organisations of parties must be provided as reasonably required.

(7) The parties must take all reasonable measures to control unauthorised access to confidential information and to ensure secure information exchange.

(8) Parties must report to the information owner any leak of information that is governed by a confidentiality agreement as soon as practicable after they become aware of the leak and must provide the information owner with all reasonable assistance to ensure its recovery or destruction, as considered appropriate by the information owner.

PART 3
CYBER SECURITY

Cyber security minimum standards compliance

68. (1) Participants must comply to IEC 62351 “Power systems management and associated information exchange - Data and communications security”.

(2) Participants shall establish, implement, maintain and continually improve an information security management system in compliance to IEC 27001.

(3) The information technologies security controls and techniques of the participants must be in compliance to IEC 27002.

(4) Participants must establish a risk management system for risk identification, analysis, evaluation and treatment in compliance to IEC 27005.

(5) The security of industrial automation and control systems of the participants must be in compliance to IEC 62443.

(6) The information security for power system control operations of the participants and other relevant parties must be in compliance to IEC 62351.

Cyber security requirements

69. (1) Participants with a demand or power station greater than 2.5 MW must be IEC 27001 certified.

(2) When performing cyber security risk assessments, participants must use the methodologies

developed by the cyber security working group as required in code 200 of the Transmission Grid Code.

(3) Participants must implement all cyber security risk treatment plans recommended by the cyber security working group in its report or any individual recommendation.

(4) Participants must report to the cyber security working group any cyber security incident that has a risk to the stability, operability, and reliability of the distribution power system, as promptly as reasonably practicable in the circumstances of the incident.

(5) Participants must have a recovery plan to recover from a cyber security incident to ensure the continuous stability, operability, and reliability of the distribution power system.

(6) The recovery plan must be tested in a regular way with all interested participants.

(7) Participants must identify and protect generation plant and substations and their associated primary control centres that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading within of the distribution power system, transmission power system and interconnections to the Southern African Power Pool.

Compliance with national requirements for cyber security

70. Participants must, in addition to compliance with codes 68 and 69, comply with relevant Namibian legal requirements for cyber security.

CHAPTER 6
DISTRIBUTION POWER SYSTEM MARKET CODE

PART 1
DISTRIBUTION CAPACITY

ALLOCATION AND CONGESTION MANAGEMENT

Non-discrimination for distribution capacity allocation and congestion management

71. (1) A distributor must ensure distribution capacity allocation and congestion management for the distribution power system is provided on a non-discriminatory basis including:

(a) long term distribution capacity requirements, which include all MSB bilateral trades in the distribution power system which are trades that are longer than a year up to 20 years ahead;

(b) rolling year ahead daily predicted peak hour, midday and the predicted off-peak hour available distribution capacity for all substations where the capacity exceeds 1 MW and for all MSB participants in the distribution power system.

(2) Long-term bilateral trades capacity calculations must be calculated by the distribution power system operator on an ad-hoc basis when requests are received from MSB market participants or system operator.

(3) The distribution power system operator must annually calculate the available transfer capacity in accordance with the methodology defined in code 206 of the Transmission Grid Code.

(4) The distribution power system operator must annually calculate and publish the minimum monthly available transfer capacity information specific to each distribution substation greater than 1 MW for the 20 year-ahead forecasts and the available transfer capacity must be calculated for at least the predicted peak hour, midday and the predicted off-peak hour in the month and the minimum available transfer capacity must be calculated for both import to and export from each distribution substation greater than 1 MW.

(5) The distribution power system operator must calculate available transfer capacity for all bilateral trade requests received from embedded generators within the distribution power network.

(6) Proposed bilateral energy contracts may not be approved by the distribution power system operator should there not be sufficient transmission capacity.

(7) The distribution power system operator must inform the system operator if any planned distribution maintenance impacts the available transfer capacity.

Congestion management

72. (1) The congestion management must be according with rule 11 of the MSB market rules.

CHAPTER 7
GENERAL

Transitional provisions for cyber security

73. (1) A participant who becomes a participant after commencement of this Code must comply with the provisions of codes 68 and 69 immediately upon becoming a participant.

(2) A participant who is a participant before the commencement of this Code must, within five years after the commencement of this Code, or such subsequent additional periods of six months each as may be extended by the Board, at own cost, comply with the provisions of codes 68 and 69.

ANNEXURES

ANNEXURE 1
SAMPLE CONFIDENTIALITY AGREEMENT FOR INFORMATION TRANSFER TO THIRD PARTIES

CONFIDENTIALITY AGREEMENT
BETWEEN

……

(HEREINAFTER REFERRED TO AS THE *INFORMATION OWNER*)
AND

……..

(HEREINAFTER REFERRED TO AS THE RECIPIENT)

IN RESPECT OF INFORMATION SUPPLIED TO PERFORM THE FOLLOWING WORK:

……

(HEREINAFTER REFERRED TO AS THE WORK)
ON BEHALF OF

……

(HEREINAFTER REFERRED TO AS THE CLIENT).

(i) The Recipient agrees to treat all information (hereinafter referred to as the Information) received from the Information Owner, whether in hard copy or electronic format, as strictly confidential.

(ii) The Recipient agrees to disclose the Information only to persons who are in its permanent employ, and who require access to the Information to perform their duties on behalf of the Client.

(iii) Persons other than those described in Clause 2 above, including but not restricted to temporary employees, subcontractors, and sub-consultants, must enter into separate Confidentiality Agreements with the Information Owner prior to receiving the Information.

(iv) The Recipient undertakes to use the Information only to perform his or her duties on behalf of the Client, and for no other purpose whatsoever.

(v) On completion of the services, the Recipient must at his or her expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him or her by the Information Owner. The Recipient must furthermore ensure that all duplicate copies of the Information in his or his employees' possession (electronic as well as hard copy format) are destroyed.

(vi) The Recipient must take all reasonable measures to protect the security and integrity of the Information.

(vii) If requested to do so by the Information Owner, the Recipient must forthwith at his or her expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him or her by the Information Owner. The Recipient must furthermore

ensure that all duplicate copies of the Information in his or her employees' possession (electronic as well as hard copy format) are destroyed.

(viii) The Recipient must report any leak of the Information, howsoever caused, to the Information Owner as soon as practicable after he or she becomes aware of the leak, and must provide to the Information Owner with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the Information Owner).

Signed at ..... on this the ..... day of

.....by (full name) .....

.....in his/her capacity as .....on behalf of ....

....., the Information Owner

Signed at ..... on this the ..... day of

.....by (full name) .....

.....in his/her capacity as .....on behalf of ....

..... , the Recipient