



GOVERNMENT GAZETTE

OF THE

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No. 561 Transmission Grid Code: Electricity Act, 2007 1

General Notice

ELECTRICITY CONTROL BOARD

No. 561

2018

TRANSMISSION GRID CODE: 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, has made the Transmission Grid Code set out in the Schedule.

G. HINDA
CHAIRPERSON
BY ORDER OF THE BOARD

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CHAPTER 1 INTRODUCTORY PROVISIONS

Definitions

1. In this code a word or an expression to which a meaning has been given in the Act has that meaning and unless the context otherwise indicates -

“ancillary services” -

- (a) means services supplied to the transmission company by generators, distributors or end-use customers -
 - (i) for the reliable and secure transport of power from generators to distributors and customers; and
 - (ii) to maintain the short-term reliability of the interconnected power system; and
- (b) may include -
 - (i) the various types of reserves, black start and constrained generation;
 - (ii) operating reserves;
 - (iii) black start and islanding;
 - (iv) reactive power compensation and voltage control from units;
 - (v) regulation and load following; or
 - (vi) near 50Hz resonance control service.

“area control error” means the mismatch between the instantaneous demand and supply of a control area which combines the frequency error and the tie line schedule error;

“automatic generation control” means the automatic centralised closed loop control of generating units, by means of the computerised energy management system of the system operator, where unit output is controlled by changing the set point on the governor;

“auxiliary supply” means the supply of electricity to auxiliary systems of a unit or substation equipment;

“black start” means the provision of generating equipment that, following a total system collapse (black out), is able to -

- (a) start without an outside electrical supply; and

- (b) energise a defined portion of the transmission system so that it can act as a start-up supply for other capacity to be synchronised as part of a process of re-energising the transmission system;

“busbar” means an electrical conduit at a substation where lines, transformers and other equipment are connected;

“co-generator” means a unit that is part of a specific industrial or production process and is not connected to the transmission system;

“constrained generation” means the difference between the energy scheduled at the point of connection of the generator under the unconstrained schedule, and the energy scheduled at the point of connection under the constrained schedule derived to accommodate transmission system constraints;

“control area” means a subset of SAPP that adheres to the minimum requirements for a control area as set out in the SAPP Operating Guidelines;

“control centre” means an entity responsible for the operational control of electricity network assets;

“customer” means a person that contracts directly with a transmission company for the provision of transmission services and may include a generator, distributor or end-use customer;

“distribution” means the conveyance of electricity to a customer through a distribution system which consists wholly or mainly of medium and low voltage networks;

“distribution system” means an electricity network consisting of assets -

- (a) which may include substations, transformers, cables, lines and associated equipment; and
(b) which are operated at medium voltage and low voltage;

“distributor” means a licenced entity that owns, operates and maintains a distribution system;

“disputes” means unresolved complaints between parties that require intervention;

“embedded generator” means a unit, other than a co-generator, that is not directly connected to the transmission system;

“emergency” means a situation where transmission or distribution service-providers have an unplanned loss of facilities or another situation beyond their control that impairs or jeopardises their ability to supply their system demand;

“emergency outage” means an outage when plant has to be taken out of service so that repairs can immediately be affected to prevent further damage or loss;

“end-use customer” means users of electricity connected to the transmission system;

“firm supply” means a supply that enjoys a level of reliability as specified in code 139;

“flicker” means a cyclic voltage fluctuation, normally between 0, 1 Hz and 10 Hz, that causes optical stress to humans;

“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;

“frequency” means the number of oscillations per second on the AC waveform;

“GCAC” means the Grid Code Advisory Committee established in accordance with code 5(1)(a);

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

“generator” means a legal entity operating a licenced generating unit or power station;

“governing” means a mode of operation where any change in system frequency beyond the allowable frequency dead band will have an immediate effect on the unit output according to the governor droop characteristic;

“governor droop characteristic” means the MW or Hz characteristic according to which governing will take place;

“grid code” refers to any code made as a grid code under section 3(4) of the Act;

“Grid Code Advisory Committee” means a panel of stakeholder representatives constituted as contemplated in code 11 and tasked with the review of the grid code amendments;

“grid code participant” means a legal entity that falls under the mandate of the grid code and typical grid code participants include -

- (a) licenced generators;
- (b) licenced traders;
- (c) licenced importer;
- (d) licenced exporter;
- (e) licenced transmitters who include wires businesses, supply businesses and metering administrators;
- (f) licenced distributors;
- (g) licenced suppliers; and
- (h) end-customers who connect directly to the high voltage network;

“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;

“interconnected power system” means the transmission system and any other connected system elements that are likely to have an impact on the electricity supply at a national level, including power stations with a capacity of more than 500 kVA and networks linking such power stations to the transmission system;

“interruptible load” means the consumer load or a combination of consumer loads that can be contractually interrupted without notice or reduced by remote control or on instruction from the system operator. Individual contracts place limitations on usage;

“interruption of supply” means an interruption of the flow of power to a point of supply not requested by the customer;

“imbalance” means the mismatch between the energy scheduled at a point of supply or a generator point of connection and the actual energy metered at that point of supply or generator point of connection over a scheduled period;

“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;

“load following” means the provision of generation and load response capability, including capacity, energy, and manoeuvrability, that is dispatched by system operator to match power generation and load demand within a scheduling period;

“load reduction” means the ability to reduce customer demand by load curtailment and load shedding;

“losses” means the technical or resistive energy losses incurred on the transmission system;

“major incident” means an incident where -

- (a) more than 20 system minutes of load was interrupted; or
- (b) severe damage to the plant has occurred.

“manual load shedding” means the load reduction obtained by manually shedding load at convenient points on the distribution system within 10 minutes of the instruction being issued by the system operator;

“maximum continuous rating” means the capacity that a generating unit is rated to produce continuously under normal conditions;

“metering” means all the equipment employed in measuring the supply together with the apparatus directly associated with it;

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

“participant” includes -

- (a) a generator with a power station where the total installed generating capacity is greater than 10 MVA;
- (b) generators with power stations connected to any transmission system;
- (c) generators embedded in any distribution system connected to any transmission system;
- (d) generators providing ancillary services for system operation purposes;
- (e) distributors connected to any transmission system;
- (f) end-use customers connected to any transmission system, or their respective distributor acting on their behalf;
- (g) a retailer or other wholesale market participant required to contract for the use of any transmission system;

- (h) transmission companies;
- (i) the system operator;
- (j) other participants, in the ancillary services market, with interruptible loads; or
- (k) the market operator;

“party” means any participant or the Board;

“planned interruption” a planned outage that will interrupt customer supply;

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

“point of common coupling” means the electrical node, normally a busbar, in a transmission substation where different feeders to customers are connected together for the first time;

“point of connection” means the electrical node in a transmission substation where the assets of a customer are physically connected to the assets of a transmission company;

“point of supply” means a transmission substation where energy can be supplied to distributors and end-use customers;

“power station” means one or more units at the same physical location;

“power quality directive” means the Board directive for the management of power quality in the electricity supply industry;

“primary substation equipment” means high voltage equipment installed at substations;

“protection” means the process of clearing a fault on the interconnected power system in order to protect plant and people;

“quick reserve” means interruptible load or capacity readily available which can be started and loaded within 10 minutes to meet the system demand. This includes hydro plant, gas turbines, pumped storage and interruptible load;

“quote” means a legal document given to a customer for the purpose of providing a price for specified transmission services;

“regulating reserve” means a reserve that is under automatic generation control and has the generation capacity or customer loads to respond within 10 seconds and be fully active within 10 minutes of activation;

“regulation” means the provision of generation and load response capability, including capacity, energy and manoeuvrability that responds to automatic control signals issued by the system operator;

“risk-related outage” means a planned outage where the next credible contingency would result in a loss of load, loss of supply, voltage slide, thermal overload or dynamic stability constraint;

“SAPP” means the Southern Africa Power Pool -

- (a) founded in 1995 as a cooperation of national electricity companies in Southern Africa; and

(b) consisting of utilities of SADC member states;

“scheduling” means a process to determine which unit or equipment will be in operation and at what loading;

“security” means the probability of not having an unwanted operation;

“service provider” means any licenced transmission company;

“single buyer” means the entity responsible for administering the electric energy market and the ancillary services market including daily scheduling and settlement;

“speed of operation” means the time taken to clear a fault on the interconnected power system;

“spinning reserve” means the unused capacity which is synchronized to the system and which can be delivered immediately without manual intervention;

“stakeholders” means the entities affected by or having a material interest in the Transmission Grid Code including customers and other participants, the Board, the single buyer and the SAPP;

“substation” means a site at which switching or transformation equipment is installed;

“system frequency” means the frequency of the fundamental AC voltage as measured at selected points by the system operator;

“system minutes” means the normalised performance indicator for interruptions calculated as System Minutes interrupted = energy interrupted (MWh) * 60 / system peak demand (MW);

“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;

“transmission” means the conveyance of electricity by means of a transmission system, which consists wholly or mainly of high voltage networks and electrical plant, from an energy source or system to a customer;

“transmission company” means an entity that holds a valid transmission licence and depending on the licence conditions may be responsible for -

- (a) system operations;
- (b) transmission supply business;
- (c) transmission wires business;
- (d) imports and exports; and
- (e) single buyer;

“transmission company outage scheduler” means a person appointed by the transmission company to check for multiple requests for an outage of the same network unit;

“transmission equipment” means the equipment that is needed for the purpose of transmission;

“transmission metering administrator” means a licenced transmission company that is responsible for all transmission tariff metering installation, maintenance and operations;

“transmission supply business” means a licenced transmission company that is responsible for supplying energy to transmission customers;

“transmission network” means the electricity transmission network owned and operated by the transmission company.

“transmission system” means an electricity network consisting of assets including substations, transformers, cables, lines and associated equipment, which are operated wholly or mainly at a high voltage;

“transmission wires business” means a licenced transmission company that is responsible to install, operate and maintain transmission equipment; and

“unplanned outage” means an outage that is not requested, negotiated, scheduled and confirmed 14 days before the outage takes place but does not include a forced outage, emergency outage or opportunity maintenance.

Objectives of Transmission Grid Code

2. (1) The objectives of the Transmission Grid Code are to -
 - (a) establish the rules and procedures that allow a person to use the power system;
 - (b) permit the power system to be planned and operated safely, reliably, efficiently and economically;
 - (c) be objective, transparent, non-discriminatory and consistent with Government policy;
 - (d) provide for the overall administration and review of the various aspects of -
 - (i) the Transmission Grid Code; and
 - (ii) the Distribution Grid Code published in terms of section 3(4)(a) of the Act as the Transmission Grid Code must be read in conjunction with the relevant legislation, licences issued to generators, transmission companies and distributors, and other operating codes that relate to the Electricity Supply Industry;
 - (e) set the -
 - (i) connection conditions for generators, distributors and end-use customers; and
 - (ii) standards used to plan and develop the transmission system;
 - (f) set out the responsibilities and roles of the participants as far as the Interconnected Power System (IPS) is concerned and more specifically issues related to -
 - (i) reliability, security and safety of the interconnected power system;
 - (ii) ancillary services;
 - (iii) market operation actions required by the system operator;

- (iv) independent actions required and allowed by customers;
 - (v) operation of the interconnected power system under abnormal conditions; and
 - (vi) field operation, maintenance and maintenance coordination or outage planning;
- (f) ensure a metering standard for all current and future participants;
- (g) specify metering requirements to be adhered to;
- (h) clarify levels of responsibility relating to metering requirements contemplated in paragraph (g);
- (i) define the obligations of participants with regard to the provision of information for the implementation of the code.
- (2) Information exchanged between parties governed by the code is confidential unless otherwise stated.
- (3) The NRS 057:2001 metering specifications must be used as the metering requirements for the Transmission Grid Code.
- (4) Despite subcode (3), the Board may override some sections of the NRS specifications should it find them inadequate or divergent from Chapter 5.
- (5) If an aspect is not fully or clearly addressed in the NRS 057:2001 metering specifications or if a conflict arises between the provisions of the code and the NRS 057:2001 metering specifications, the code takes precedence over the NRS 057:2001 metering specifications.

Application of Transmission Grid Code

3. (1) This Transmission Grid Code applies to all users of the transmission system including distributors, embedded generators, end-use customers, retailers, re-sellers and any other entities with equipment connected to the distribution system.

(2) The provisions of this Transmission Grid Code relating to the transmission system metering apply to all participants in respect of any metering point at the boundary of the transmission system.

CHAPTER 2

TRANSMISSION SYSTEM GOVERNANCE

PART 1

TRANSMISSION GRID CODE ADMINISTRATIVE AUTHORITY AND CONSTITUTION OF TRANSMISSION GRID CODE ADVISORY COMMITTEE

Administrative authority

4. The Board is the administrative authority for the Transmission Grid Code and the Board must ensure that the Transmission Grid Code is compiled, approved and implemented for the benefit of the electricity industry.

Establishment of Grid Code Advisory Committee

5. (1) The Board must -
 - (a) establish a Grid Code Advisory Committee; and
 - (b) ensure the proper functioning of the GCAC contemplated in paragraph (a).
- (2) The GCAC is established to -
 - (a) ensure a consultative stakeholder process is followed in the formulation and review of the grid code;
 - (b) review and make recommendations regarding proposals to amend the grid code;
 - (c) review and make recommendations regarding proposals for exemption to comply with the grid code; and
 - (d) facilitate the provision of expert technical advice to the Board on matters related to the grid code.

Constitution of GCAC

6. (1) The GCAC is a stakeholder representative panel, representing participants.
- (2) Members of the GCAC must ensure that they consult with their constituencies with respect to their role on the GCAC.
- (3) The Board must annually review the composition of and constituencies represented by the GCAC to ensure that it is at all times reflective of the evolving industry.
- (4) The Board may decide to expand the composition of the GCAC as part of the membership review process in consultation with the GCAC.
- (5) The Board must ensure that members on the GCAC are able to make meaningful contributions towards the membership review process contemplated in subcode (4).
- (6) The GCAC must consist of at least the following members:
 - (a) one member representing the system operator;
 - (b) one member representing transmission companies;
 - (c) two members representing generators;
 - (d) two members representing distributors;
 - (e) one member representing large end-use customers; and
 - (f) two Board members, one to chair and the other to assist the secretariat.
- (7) The members must be identified as follows:
 - (a) if an industry association represents the larger part of the constituency, the association will be requested to make the nomination;

- (b) if the constituency consists of more than one association or a relatively small number of entities, calls for nominations will be sent to all entities and the Board may -
 - (i) decide on the member if more than the required number of nominations are received; or
 - (ii) choose the member if no nominations are received; or
- (c) if there is no identifiable entity, a public call for nomination will be sent out by the Board and the Board may decide on the member if more than the required number of nominations are received.
- (8) The Board must publish changes in membership within 14 days, on the website of the Board.
- (9) GCAC members must serve a three year term, after which they are eligible for reappointment.
- (10) Despite subcode (9), the -
 - (a) constituency of a GCAC member may replace that member at any given time but a 14 days written notice must be given to the secretariat of the GCAC and to the Board before the replacement; or
 - (b) Board may, on the recommendation of the GCAC, request the constituency of a GCAC member to replace that member if that member has not attended three consecutive meetings.
- (11) GCAC members must nominate an alternative representative and that nomination must be made in writing to the secretariat of the GCAC.

Functioning of GCAC

7. (1) The GCAC must review all proposals for amendment of or exemptions from the Transmission Grid Code.
- (2) The GCAC must schedule at least one annual review session and the format of a session may be determined by the GCAC, but should include a work session if proposed changes are of a substantive nature.
- (3) Agenda items for a session contemplated in subcode (2) must be circulated at least 14 days in advance of the session.
- (4) The GCAC must -
 - (a) subject to code 6, determine its own meeting procedures and code of conduct; and
 - (b) publish the meeting procedures and code of conduct, contemplated in paragraph (a), on the website of the Board.
- (5) A Board member must chair the GCAC meetings and if that Board member or his or her alternate is unable to attend the GCAC meeting that Board member or his or her alternate must make arrangements for an alternative chairperson for the duration of the meeting.

(6) A quorum at GCAC meetings consists of 50 percent of GCAC members plus one member of the Board, and the GCAC must take decisions by means of a majority vote of the GCAC members constituted as contemplated in code 6(6), and if votes are even then the Chairperson has the deciding vote.

(7) Alternate members must be allowed to vote only when the main member is not available for voting.

(8) If a quorum is not present within 30 minutes of the starting time for a GCAC meeting, as specified by the secretariat in a written notice issued to GCAC members, the members at the meeting must make the necessary recommendations to GCAC members and the secretariat must circulate the necessary recommendations electronically to all GCAC members for decision within a period of five work days.

(9) On receipt of the recommendations contemplated in subcode (8), the GCAC members must, within the period contemplated in that subcode, make a decision and communicate the decision in writing to the secretariat.

(10) The decision contemplated in subcode (9) is effective only if voted on by a quorum.

(11) If a decision is voted on as contemplated in subcode (10), the decision must be minuted as confirmed at the next GCAC meeting where a quorum is present.

(12) The secretariat must record all the decisions of the GCAC including the dissenting views expressed by GCAC members.

(13) The Board must fund the administrative activities of the GCAC but GCAC members are responsible for their own travel and subsistence expenditure.

(14) The GCAC may -

(a) co-opt experts with the purpose of allowing expert opinion to be obtained regarding complicated submissions;

(b) encourage industry participation and consultation in the activities of the experts contemplated in paragraph (a); or

(c) obtain industry participation and consultation through the activities of the experts contemplated in paragraph (a).

(15) The GCAC must provide the experts contemplated in code 14(a) with a full scope of work and an urgency indicator for each task referred to them.

(16) The Board must, in addition to its mandate under section 3(4)(a), publish the Transmission Grid Code or any amendments to the Transmission Grid Code, on its website.

Secretariat of transmission and distribution grid codes

8. (1) The system operator is appointed as the secretariat of the transmission and distribution grid codes subject to review by the Board and the secretariat is accountable to the Board and the GCAC for its activities.

(2) The functions of the secretariat are to -

(a) ensure procedures are developed and published for the review of proposed amendments and exemptions by the GCAC;

- (b) provide standard submission forms to participants;
 - (c) assist, when requested, in the preparation of submissions to the GCAC;
 - (d) prepare amendment and exemption proposals for submission to the Board following review by the GCAC;
 - (e) manage grid code documentation;
 - (f) disseminate relevant information;
 - (g) inform participants of the progress with applications for amendment or exemption;
 - (h) co-ordinate the activities of the GCAC;
 - (i) keep and circulate minutes of meetings and documentation of proceedings of the GCAC;
 - (j) register participants as contemplated in code 14; and
 - (k) function as a formal communication channel for the GCAC.
- (3) The secretariat must make the latest version of the grid code available electronically and notify all participants of approved amendments or exemptions within one week of receipt of approval by the Minister of Mines and Energy.
- (4) The secretariat must make hard copies of the latest version of the grid code available to requesting entities, for which a nominal fee may be charged to recover reproduction costs.

PART 2
REGISTRATION OF PARTICIPANTS AND GRID CODE
AMENDMENT OR EXEMPTION

Registration and deregistration of participants

9. (1) A participant may be registered by the secretariat as a generator, distributor, end-use customer, service provider, retailer or market participant.
- (2) A participant must apply in writing to the secretariat to be registered as contemplated in subcode (1).
- (3) A participant may not have access to the transmission system unless the participant is registered as contemplated in subcode (1).
- (4) Service providers must ensure that customers are registered as participants before entering into a contract for licenced services with the customers.
- (5) A participant who intends to deregister must notify the secretariat at least six months before the intended date of deregistration and the deregistration must be carried out in accordance with guidelines determined by the Board.

Transmission Grid Code amendment or exemption process

10. (1) A participant, a member of the GCAC or a member of the Board -

- (a) may in writing to the Minister propose amendments to the Transmission Grid Code; and
 - (b) who proposes amendments pursuant to paragraph (a), must submit the proposed amendments to the secretariat as contemplated in code 11(4).
- (2) A participant -
- (a) may in writing to the Minister apply for an exemption from complying with provisions of the Transmission Grid Code; and
 - (b) who applies for an exemption pursuant to paragraph (a), must submit the application to the secretariat as contemplated in code 11(4).
- (3) On receipt of the proposed amendments contemplated in subcode (1) or the application contemplated in subcode (2) -
- (a) the secretariat must submit the proposed amendments or the application to the GCAC for review; and
 - (b) subject to paragraph (a) and code 7, the GCAC must review the proposed amendments and subject to code 12(1), make recommendations to the Board.
- (4) Subject to code 12, the Minister -
- (a) may approve the amendments proposed under subcode 1; or
 - (b) must approve and grant an exemption applied for under subcode 2, if the exemption is necessary to -
 - (i) provide for existing equipment that has not been designed with consideration for the provisions of the Transmission Grid Code;
 - (ii) facilitate transition through interim arrangements; or
 - (iii) facilitate temporary conditions necessitating exemption.
- (5) The GCAC must keep a register which contains a list of exemptions that have been approved under subcode (4), with the relevant expiry date and the reference number.
- (6) The procedure for the amendment of, or exemption from, the Transmission Grid Code as contemplated in subcodes (1) to (4) inclusive, is sketched in Annexure 1.

Submissions to GCAC

- 11.** (1) The secretariat must make available a list of submission dates aligned with GCAC annual meetings for each year by November of the preceding year.
- (2) Urgent submissions must be dealt with at *ad hoc* meetings of the GCAC as decided by the Chairperson upon advice from the secretariat.
- (3) The secretariat must issue guidelines for submissions to the GCAC and the guidelines must be published together with the submission dates on the website of the Board.

(4) An application for an amendment or exemption must be submitted, in accordance with the guidelines, to the secretariat and the applicant must state the relevant clauses of the Transmission Grid Code and give reasons for the application.

(5) The GCAC must initiate the review process without delay and must -

(a) if necessary, ensure that the submission is referred to an expert team for detailed assessment, clarification and reformulation or recommendation; and

(b) forward the recommendation to the Board for consideration once it has been finalized.

(6) The GCAC must take the complexity and importance of the amendment or exemption into account in deciding on the composition of the expert team that will deal with the submission.

(7) The secretariat must inform the applicant of the expected time frames for dealing with the submission.

(8) The applicant must be allowed to make representation to the expert team or the GCAC prior to the formulation or finalization of the GCAC recommendation to the Board.

Recommendation to Board

12. (1) Once the GCAC has reviewed submissions, the secretariat must prepare the formal recommendation to the Board on all proposed amendments to, and exemptions from, the Transmission Grid Code.

(2) In the recommendation contemplated in subcode (1), the secretariat must include -

(a) a clear expression of divergent views on the proposed amendments and exemptions if any were received by the secretariat; and

(b) an appropriate implementation date for the proposed amendments and exemptions.

(3) Despite any code to the contrary, the Minister may grant full or partial exemption to participants from complying with any code.

(4) The Board must submit its recommendations for amendments or exemptions to the Minister for approval.

(5) Amendments and exemptions must have an implementation date stipulated by the Minister.

(6) The Board must give notice to the secretariat of the decisions reached by the Board and the Minister.

(7) The secretariat is responsible for communicating the decisions contemplated in subcode (6) to participants.

(8) The secretariat must update the Transmission Grid Code with the approved amendments and exemptions.

PART 3
DISPUTE MEDIATION, RESOLUTION AND APPEAL MECHANISM

Dispute mediation, resolution and appeal mechanism

13. (1) A registered participant must have a documented procedure for handling disputes arising under the Transmission Grid Code.

(2) The procedure contemplated in subcode (1) must cover the aspects contemplated in code 17.

Complaints about operations of GCAC

14. (1) Any complaint regarding the operations of the GCAC must be addressed in writing to the secretariat.

(2) The GCAC must attend to the complaints contemplated in subcode (1) at or before the next session.

(3) If a complaint contemplated in subcode (1) is not resolved at the meeting contemplated in subcode (2), the matter must be referred to the Board in accordance with code 17.

Disputes about decisions of Board

15. (1) Any objection to decisions by the Board must be made in writing to the Board.

(2) Participants who are aggrieved by decisions taken by the Board may appeal to the Minister, against the decisions taken by the Board, in accordance with Section 34 of the Act.

Disputes about decisions of Minister

16. (1) Any objection to decisions by the Minister must be made in writing to the Minister.

(2) Participants who are aggrieved by decisions taken by the Minister may appeal to the High Court against the decisions taken by the Minister.

Complaints among customers and service providers

17. (1) The procedure for handling complaints must include the incident report and non-conformance report requirements set out in codes 18 and 19.

(2) The Board must develop a database of disputes resolved to assist in the resolution of future disputes.

(3) If the outcome of a dispute resolution proceeding requires or implies an amendment to the Transmission Grid Code, the Board must first consult with the GCAC.

Incident report

18. (1) An incident report should be seen as a formal communication of a problem.

(2) A customer may issue an incident report to a service provider on becoming aware of a problem or a possible breach of the Transmission Grid Code.

(3) The service provider contemplated in subcode (2) must provide a reasonable explanation and if appropriate indicate what action it will take to address the problem.

(4) A service provider may issue an incident report to a customer if the customer is suspected of not complying with the necessary Transmission Grid Code requirements and the customer must provide the service provider with a reasonable explanation and where appropriate indicate the measures that the customer will take to address the problem.

(5) A service provider must keep a log of all incident reports received and a log of all incident reports communicated to customers.

(6) Incident reports are operational in nature and generally require action only by technical and customer relations staff.

Non-conformance report

19. (1) A customer may issue a non-conformance report when it is suspected that -

(a) the service provider has -

(i) failed to provide a reasonable explanation;

(ii) wilfully misrepresented the facts concerning an incident; or

(iii) failed to implement the agreed preventative actions within the agreed time frame;

(b) the number of incident reports is excessive in relation to historical performance; or

(c) the actions or undertakings arising from a mediation or arbitration process have not been performed or adhered to.

(2) A service provider may issue a non-conformance report when it is suspected that -

(a) the customer has failed to provide a reasonable explanation;

(b) the customer has wilfully misrepresented the facts concerning an incident; and

(c) the customer has failed to implement the agreed preventative actions within the agreed time frame;

(d) the number of incident reports is excessive in relation to historical performance; or

(e) the actions or undertakings arising from a mediation or arbitration process have not been performed or adhered to.

(3) Non-conformance reports are indications of problems that require managerial intervention by the service provider or customer.

(4) In the case where the parties agree with the non-conformance report, recommended action must be agreed upon and both participants must implement the recommended action within an agreed time frame.

(5) Service providers must report annually to the Board on the following aspects of the procedure:

- (a) Number of non-conformance reports for each customer category;
- (b) Number of closed out non-conformance reports for each customer category; and
- (c) Number of disputes resolved.

(6) A dispute may be declared when the parties cannot agree on the non-conformance report or the recommendations of the non-conformance report or when the agreed recommendations are not implemented in the agreed time frame.

Submission of disputes to Board

20. (1) A party may submit a dispute to the Board in accordance with the procedures contemplated in codes 14 and 17.

(2) When a dispute is submitted to the Board as contemplated in subcode (1) or referred to the Board as contemplated in code 14(3) the parties must provide the following information:

- (a) full history of relevant incident reports;
- (b) detailed non-conformance report and accompanying information that gave rise to the dispute; and
- (c) written report from each participants detailing the reason for not being able to close out the non-conformance report.

(3) When a dispute that has not followed the relevant procedure reaches the Board, the Board must refer the party to the correct process.

(4) The Board must conduct a dispute mediation process and act as the mediator to the dispute in accordance with -

- (a) section 3(2)(c) of the Act; and
- (b) the dispute mediation procedural rules of the Board.

(5) If the dispute mediation process contemplated in subcode (4) succeeds, the parties must strive to honour their respective undertakings or actions agreed upon to the best of their abilities.

(6) If the dispute mediation process contemplated in subcode (4) fails to provide the parties with an agreed solution, the parties must refer the matter to arbitration for final decision.

(7) If the issue to be resolved at the mediation contemplated in subcode (4) is primarily -

- (a) an accounting matter, there must be one arbitrator who is an independent Chartered Accountant;
- (b) a legal matter, there must be one arbitrator who is a senior counsel; or
- (c) a technical matter, there must be one arbitrator who is a person with suitable technical knowledge.

(8) The appointment of the arbitrator must be agreed between the parties, but failing agreement between them within a period of 14 days after the arbitration has been demanded, either of the parties may request the Board to make the appointment and, in making the appointment, to have regard to the nature of the dispute.

(9) Each arbitration must be in Windhoek in accordance with the provisions of Namibian arbitration laws.

(10) The following must be considered, amongst other things, during the arbitration process:

- (a) existing and historical performance trends or practices;
- (b) reference standards;
- (c) appropriate network design or operation standards;
- (d) precedents with similar events;
- (e) historical agreements between the participants; and
- (f) total cost impact.

(11) The ruling of the arbiter must include a time frame for implementation and is final and binding on the parties.

PART 4

COMPLIANCE, CODE AUDITS, CONTRACTING AND VERSION CONTROL

Compliance

21. (1) All participants must comply with the Transmission Grid Code.

(2) Participants must inform the Board of any non-conformance report of a material nature that has been submitted to another participant as contemplated in code 24.

(3) The Board may require a participant to provide the Board with information that the Board considers necessary for the proper administration of the Transmission Grid Code and that information must on request be treated as confidential.

(4) Upon a report or suspicion of non-compliance the Board may seek to -

- (a) resolve the issue through negotiation;
- (b) take action in terms of the procedures for handling licensing contraventions;
- (c) consider an application for amendment; or
- (d) consider an application for exemption.

(5) Customers may apply for exemption from changes to the Transmission Grid Code as contemplated in code 10.

Code audits

22. (1) A customer may request from the service provider or a service provider may request from a customer, any material in the possession or control of that participant relating to compliance with a particular code of the Transmission Grid Code.

(2) If a participant makes a request in relation to a particular code of the Transmission Grid Code as contemplated in subcode (1) the participant may not request information relating to that same code of the Transmission Grid Code within six months.

(3) A request contemplated in subcode (1) must include the following information:

- (a) nature of the request;
- (b) name of the representative appointed by the requesting participant to conduct the investigation; and
- (c) the time or times at which the information is required.

(4) The participant contemplated in subcode (1) -

- (a) may not unreasonably withhold any relevant information requested; and
- (b) must provide a representative of the requesting participant with access to all relevant documentation, data and records, including computer records or systems, as is reasonably requested.

(5) The information contemplated in subcode (4) must be treated as confidential on request to do so.

(6) A request contemplated in subcode (1) or an investigation must be conducted without undue disruption to the business of the participant.

Contracting

23. (1) The Transmission Grid Code must comprise one of the standard documents that form part of the contract between participants.

(2) Service providers must contract with customers for any services specified in the Transmission Grid Code in accordance with the contracting framework sketched in Annexure 2.

(3) Service providers must ensure that a non-discriminatory procedure is developed and implemented for the allocation of quality of supply parameters at the points of common coupling.

(4) Customers must enter into a connection contract and an operating agreement with the transmission company in advance of construction of the connection facilities.

(5) Customers must enter into a use-of-system contract with the transmission company before commencement of energy transactions over the transmission system.

(6) Customers must enter into an ancillary services contract with the transmission company before commencement of ancillary services delivery to the transmission company.

Version control

24. (1) The Transmission Grid Code will evolve as the electricity supply industry in Namibia evolves.

(2) The chapters and codes that collectively form the grid code must have separate version control and approvals.

- (3) The secretariat is responsible for version control.

CHAPTER 3
TRANSMISSION SYSTEM NETWORK

PART 1
TRANSMISSION SYSTEM CONNECTION PROCESS AND CONDITIONS

Applications for transmission system connections

25. (1) The transmission company must provide quotes for new connections or for upgrading existing connections, according to a tariff methodology approved by the Board, within time frames agreed with prospective customers.

(2) The agreed time period for connecting customers or upgrading connections must be negotiated between the transmission company and the customer in every instance.

(3) Applications for new or revised connections must be lodged with the transmission company at NamPower Centre, 15 Luther Street, Windhoek.

Objective of connection conditions

26. (1) The -

(a) customer connected to or seeking connection to the transmission system or embedded generator or co-generator, must comply with the acceptable technical, design and operational criteria; and

(b) transmission company and system operator must comply with the minimum technical, design and operational criteria in relation to the part of the transmission system where the connection will take place.

(2) The objective of the connection conditions specified in codes 27 to 72 is to ensure -

(a) that by specifying minimum technical, design and operational criteria, the basic rules for connection to the transmission system -

(i) are similar for all customers of an equivalent category; and

(ii) will enable the Transmission company and system operator to comply with its statutory and licence obligations;

(b) adherence to sound engineering practice and codes by all the participants since quality of supply and grid integrity are shared responsibilities between the Transmission company and system operator and their customers.

Generator connection conditions

27. (1) The Transmission Grid Code requirements for generator connections are set out in subcodes (2), (3) and (4).

(2) The Transmission Grid Code requirements must be read with the generating unit characteristics and sizes specified in Table 1 and 2 in Annexure 3.

(3) The transmission company must offer to connect generators and upon signing of an agreement to connect a generator entered into by the transmission company and a generator licenced to generate electricity who has applied under code 25(3), the transmission company must make available a point of connection to that generator.

(4) For new generating units special consideration must be given to the impact of the risks on future operating costs and the system operator is to quantify the expected future operating costs.

(5) The special consideration contemplated in subcode (4) may include obtaining approval of the Board for including the expected future operating costs in the tariff base or obliging the generator to purchase reserves.

Protection

28. (1) The unit step-up transformer, unit auxiliary transformer, associated busbar ducts and switchgear of a generating unit must be equipped with well maintained protection functions, in line with international best practices, to rapidly disconnect appropriate plant sections should a fault occur within the relevant protection zones of the transmission system.

(2) The protection functions contemplated in code 29, 30, 31, 32, 33, 34, 35 or 36 may be used as specified in that code to protect the interconnected power system.

Backup impedance

29. (1) An impedance facility with a large reach must be used.

(2) The impedance facility contemplated in subcode (1) must operate for phase faults in the unit, in the high voltage yard or in the adjacent transmission system lines, with a suitable delay, for cases when the corresponding main protection fails to operate.

(3) The impedance facility contemplated in subcode (1) must have fuse fail interlocking.

Loss of field

30. (1) A generating unit must be fitted with a loss of field facility that matches the system requirements.

(2) The type of loss of field facility contemplated in subcode (1) must be agreed with the transmission company.

Pole slipping facility

31. A generating unit must be fitted with a pole slipping facility that matches the system requirements, where the system operator determines that it is required.

Trip to house load

32. (1) A trip to house load protection must operate as follows in the event of a complete loss of load -

- (a) if all the feeder breakers open at a power station, power flow into the system is cut off and the generators will accelerate;
- (b) at 50.5 Hz the over-frequency facility must pick up to start the house loading process and the high voltage breakers will still be closed;

(c) there will be power swings between the units and as soon as a generating unit has a reverse power condition the trip to house load protection must open the high voltage breaker; and

(d) the units must island feeding their own auxiliaries.

(2) When system conditions have been restored then the islanded units can be resynchronised to the transmission system.

Unit transformer high voltage back-up earth fault protection

33. (1) Unit transformer high voltage back-up earth fault protection is an inverse definite minimum time facility that must monitor the current in the unit transformer neutral.

(2) The unit transformer high voltage back-up earth fault protection can detect faults in the transformer high voltage side or in the adjacent network.

(3) The unit transformer high voltage back-up earth fault protection facility contemplated in subcode (1) must trip the high voltage circuit breaker.

High voltage breaker fail protection

34. (1) The high voltage breaker fail protection must monitor the operation of the high voltage circuit of the circuit breaker for protection trip signals.

(2) If a circuit breaker fails to open and the fault is still present after a specific time delay, nominally 120 ms, it must trip the necessary adjacent circuit breakers.

High voltage pole disagreement protection

35. The high voltage pole disagreement protection must cover the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal.

Unit switch onto standstill protection

36. (1) A unit switch onto standstill protection must be installed in the high voltage yard substation or in the unit protection panels.

(2) If the protection contemplated in subcode (1) is installed in the unit protection panels then the direct current supply for the unit switch onto standstill protection and the protection used for the circuit breaker closing circuit must be the same to safeguard the generator against an unintended connection to the transmission system, back energisation, when at standstill or at low speed.

(3) In addition, should system conditions dictate, other protection requirements must be determined by the system operator in consultation with the generator and these should be provided and maintained by the relevant generator at its own cost.

(4) Required high voltage breaker tripping, fault clearance times, including breaker operating times depend on system conditions and must be defined by the transmission company.

(5) The guidelines for the operating times contemplated in subcode (4) are -

(a) 80 ms where the point of connection is 330kV or above;

(b) 80 ms where the point of connection is 220 kV; or

- (c) 100 ms where the point of connection is 132 kV and below.
- (6) Further downstream breaker tripping-away from the system, fault clearing times, including breaker operating time, must not exceed -
- (a) 120 ms plus additional 30 ms for DC offset decay; or
- (b) 100 ms plus additional 40 ms for DC offset decay.
- (7) Where system conditions dictate, the times contemplated in subcodes (5) and (6) may be reduced.
- (8) Where so designed, earth fault clearing times for high resistance earthed systems may exceed the tripping times contemplated in subcodes (5) and (6).
- (9) All protection interfaces with the transmission company must be co-ordinated between the participants.
- (10) The settings of all the protection tripping functions on the unit protection system of a unit, relevant to the interconnected power system performance and as agreed with each generator in writing, must be co-ordinated with the transmission protection settings.
- (11) The transmission protection settings contemplated in subcode (10) must be agreed between the transmission company and the generator and must be documented and maintained by the generator with the reference copy which reflects the actual plant status held by the transmission company and the generator must control all other copies of the documented protection settings.
- (12) For system abnormal conditions, a unit is to be disconnected from the transmission system in response to conditions at the point of connection, only when the system conditions are outside the plant capability where damage will occur.
- (13) Protection setting documents must illustrate plant capabilities and the relevant protection operations.
- (14) Competent persons must carry out testing, commissioning and configuration of protection systems.
- (15) Prototype and routine testing of protection systems must be carried out as set out under item 5(1) in Annexure 4.
- (16) Any work, including work done during a unit outage, on the protection circuits interfacing with transmission protection systems must be communicated to the system operator before commencing with the works.

Ability of units to island

- 37.** (1) Every unit that does not have black start capabilities of less than one hour without power from the transmission system must be capable of unit islanding.
- (2) Islanding testing must be contracted as an ancillary service.
- (3) The procedure for islanding testing contemplated in subcode (2) is set out under item 5(2) in Annexure 4.

Excitation system requirements

38. (1) A continuously-acting automatic excitation control system (AVR) must be installed to provide constant terminal voltage control of the unit, without instability, over the entire operating range of the unit.
- (2) A continuously-acting automatic excitation control system does not include the possible influence of a power system stabiliser.
- (3) Excitation systems must comply with the requirements specified in IEC 60034.
- (4) The excitation control system must be equipped with an under-excitation limiter, load angle limiter and flux limiter as described in IEC60034-16-1.
- (5) The excitation system must have a minimum excitation ceiling limit of 1.6 pu rotor current, where 1 pu is the rotor current required to operate the unit at rated load and at rated power factor.
- (6) The settings of the excitation system contemplated in subcode (1) must be agreed between the system operator and each generator.
- (7) The settings agreed between the system operator and a generator as contemplated in subcode (6) must be documented.
- (8) The master copy of the settings documented as contemplated in subcode (7) must be held by the system operator.
- (9) The generators must control all other copies following the procedure set out in item 5(3) in Annexure 4.
- (10) In addition, the unit must be capable of operating in the full range set out in the capability chart referred to in item 2 in Annexure 9.
- (11) The capability of a unit to operate in full range as contemplated in subcode (9) must be tested using the test procedures shown in item 5(5) in Annexure 4.
- (12) The active power output under steady state conditions of any unit must not be affected by voltage changes in the normal operating range.
- (13) Units with water-cooled stator windings must be capable of delivering rated Megavolt-Ampere (MVA) at terminal voltages between 95% and 105% of rated voltage.
- (14) Units with gas-cooled stator windings are specified to be capable of delivering rated MVA at terminal voltages between 100% and 105% of rated voltage and rated stator current at voltages below 100%.
- (15) Power system stabilisers as described in IEC60034-16-1 are a requirement for all new units, and for existing units retrofitting may be required depending on the interconnected power system requirements.
- (16) The requirements for other excitation control facilities and continuously-acting automatic excitation control system (AVR) refurbishment must be determined in conjunction with the system operator.
- (17) Routine and prototype response tests must be carried out on excitation systems as indicated in item 5(3) in Annexure 4 and in accordance to IEC60034-16-3.

Reactive capabilities

39. (1) All new units must be capable of supplying rated power output Megawatt (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the unit terminals.

(2) Reactive output must be fully variable between the limits specified in subcode (1) under continuously-acting automatic excitation control system (AVR), manual or other control.

(3) Routine and prototype response tests must be carried out to demonstrate reactive capabilities as indicated in item 5(5) in Annexure 4.

Multiple unit tripping (MUT) risks

40. A power station and its units must be designed, maintained and operated to minimise the risk of more than one unit being tripped from one common cause within a short time.

Governing design requirements

41. All units above 2.5 MVA must have an operational governor that must be capable of responding according to the minimum requirements set out in codes 43 to 53.

Governing system frequency variations

42. (1) Because of the uncertain dynamic behaviour of the Namibian system, frequency variations cannot be specified in the Transmission Grid Code.

(2) New Generators will need to do comprehensive system studies to ascertain the dynamic behaviour of the system as applicable to their position on the network.

(3) The frequency tolerances apply to voltage tolerances as specified in code 57.

High frequency requirements for turbo-alternators

43. (1) All synchronised units must respond by reducing active power to frequencies above 50 Hz plus allowable dead band described in code 53.

(2) Speed governors must be set to give a four percent governor droop characteristic or as otherwise agreed by the system operator.

(3) The response under subcodes (1) and (2) must be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion.

(4) The unit must respond to the full designed minimum operational capability of the unit at the time of the occurrence.

Over-frequency conditions in range of 51.5 to 52 Hz (stage H1)

44. (1) When the frequency goes above the range of 51.5 Hz but less than 52 Hz the requirement is that the unit must be designed to run for at least 10 minutes over the life of the plant.

(2) The turbo-alternator units must be able to operate for at least five minutes continuously without tripping in the range contemplated in subcode (1).

(3) Exceeding the limit of 53Hz must prompt the generator to take all reasonable efforts

to reduce the system frequency below 51.5Hz, including manual tripping of the running unit.

(4) Tripping must be staggered in time and be initiated once the frequency has been greater than 51.5 Hz for five minutes.

(5) The generator will trip a unit, and if the system frequency does not fall below 51.5 Hz, the other units must be tripped in staggered format over the next five minutes or until the system frequency is below 51.5 Hz.

(6) The system operator must approve the tripping requirements and procedures contemplated in subcodes (1) to (5).

Over-frequency conditions above 52 Hz (stage H2)

45. (1) When the frequency goes above 52 Hz the requirement is that the unit must be designed to run for at least 1 minute over the life of the plant.

(2) The turbo-alternator units must be able to operate at least 30 seconds continuously without tripping in this range.

(3) When the system frequency exceeds 52 Hz, the generator can start tripping units sequentially and the tripping must be spread over a 30 second window.

(4) If a generator chooses to implement automatic tripping, the tripping must be staggered.

(5) The system operator must approve this the tripping requirements and procedures. As an example, the first unit will trip in 5 seconds, the second unit trip in 10 seconds, etc.

High frequency requirements for hydro alternators

46. (1) All synchronised hydro units must respond by reducing active power to frequencies above 50 Hz plus allowable dead band described in code 53.

(2) Speed governors must be set to give a four percent governor droop characteristic or as otherwise agreed by the system operator.

(3) The response under subcodes (1) and (2) must be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion.

(4) The unit must respond to the full load capability range of the unit.

(5) As the Namibian system is not designed for n-1 contingencies high over-frequency withstand capabilities are required.

(6) When the frequency goes above 54 Hz the unit must be designed to run for at least 120 seconds over the life of the plant.

(7) It is expected that there will be less than 30 events of high frequencies of over 54 Hz for the lifetime of the unit of 50 years therefore the hydro-alternator units must be able to operate at least 4 seconds in the range of frequencies above 54 Hz.

(8) When the system frequency increases to 54 Hz for longer than four seconds, the

generator must start staggered tripping of units as per the procedure for turbo-alternators.

(9) Settings of the staggered tripping of the units must be agreed with the system operator.

Low frequency requirements for turbo-alternator units

47. (1) All turbo-alternator units must be designed to be capable of having a four percent governor droop characteristic or as otherwise agreed by the system operator with a minimum response of three percent of maximum continues rating within 10 seconds of a frequency incident.

(2) The minimum response contemplated in subcode (1) must be sustained for at least 10 minutes.

Low frequency in range of 48.5 to 48.0 Hz (Stage L1)

48. (1) When the frequency is in the range of below 48.5 Hz but greater than 48.0 Hz, the turbo-alternator unit must be designed to run for at least 10 minutes over the life of the plant.

(2) The unit must be able to operate at least five minutes continuously without tripping while the frequency is in the range referred to in subcode (1).

(3) If the system frequency is in the range referred to in subcode (1) for more than five minutes, independent action may be taken by a generator to protect the unit.

Low frequency in range of 48.0 to 47.5 Hz (Stage L2)

49. (1) When the frequency goes below 48.0 Hz but greater than 47.5 Hz a turbo-alternator unit must be designed to run for at least one minute over the life of the plant.

(2) A turbo-alternator unit must be able to operate at least 30 seconds continuously without tripping while the frequency is in the range of below 48.0 Hz but greater than 47.5 Hz.

(3) If the system frequency is in the range contemplated in subcode (2) for more than 30 seconds, independent action may be taken by a generator to protect the turbo-alternator unit.

Low frequency below 47.5 Hz (Stage L3)

50. If the system frequency falls below 47.5 Hz for longer than six seconds, independent action may be taken by a generator to protect the unit.

Low frequency requirements for hydro-alternator units

51. (1) All reasonable efforts must be made by the generator to avoid tripping of the hydro-alternator for under frequency conditions provided that the system frequency is above 46 Hz.

(2) If the system frequency falls below 46 Hz for more than one second, independent action may be taken by a generator to protect the hydro-alternator unit and the action may include automatic tripping.

Droop

52. The speed governor must be capable of being set so that it operates with an overall speed droop of between two percent and nine percent.

Dead band

53. (1) The maximum allowable dead band must be 0.15 Hz for governing.
- (2) The allowable dead band for governing contemplated in subcode (1) means that no response is required from the unit while the frequency is greater than 49.85 to and less than 50.15 Hz.
- (3) Routine and prototype response tests must be carried out on the governing systems as indicated in item 5(4) in Annexure 4.

Thermal power stations restart after power station black-out

54. (1) A power station and a unit is to be capable of being restarted and synchronised to the interconnected power system following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply.
- (2) For the purposes of Chapter 3, examples of unreasonable delay in the restart of a power station are -
- (a) restart of the first unit that takes longer than four hours after restart initiation;
 - (b) restart of the second unit that takes longer than two hours after the synchronising of the first unit;
 - (c) restarting of all other units that take longer than one hour each after the synchronising of the second unit;
 - (d) delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant generator; or
 - (e) the start up facilities for a new unit not being designed to minimise start up time delays for the unit following loss of external auxiliary AC supplies for two hours or less.
- (3) Routine and prototype response tests must be carried out to demonstrate capabilities as indicated in item 5(7) in Annexure 4.

Hydro and gas turbines restart after power station black-out

55. (1) A power station and a unit is to be capable of being restarted and synchronised to the interconnected power system following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply.
- (2) For the purposes of Chapter 3, examples of unreasonable delay in the restart of a power station are -
- (a) restart of the first unit that takes longer than 30 minutes after restart initiation;
 - (b) restarting of all other units that take longer than 30 minutes each after the synchronising of the first unit;
 - (c) delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant generator; and

- (d) the start up facilities for a new unit not being designed to minimise start up time delays for the unit following loss of external auxiliary AC supplies for 30 minutes or less.

(7) Routine and prototype response tests must be carried out to demonstrate capabilities as indicated in item 5(7) in Annexure 4.

Black starting

56. (1) Power stations that have declared that they have a station black start capability must demonstrate this facility by test as described in item 5(7) in Annexure 4.

(2) Back start capable power stations may be called from time to time not to carry out a full station black start but a unit black start as described in item 5(8) in Annexure 4.

External supply disturbance withstand capability

57. (1) Any unit and any power station equipment must be designed with anticipation of the following voltage conditions at the point of connection:

- (a) a voltage deviation in the range of 90% to 110% for protracted periods;
- (b) a voltage drop to zero for up to 0.2s, to 75% for 2s, or to 85% for 60 s provided that during the three minute period immediately following the end of that 0.2s, 2s, or 60s periods the actual voltage remains in the range 90-110% of the nominal voltage;
- (c) unbalance between phase voltages of not more than three percent negative phase sequence and or the magnitude of one phase not lower than five percent than any of the other two for six hours; and
- (d) a requirement to withstand the automatic reclosing cycle for faults on the transmission lines connected to the power station, being three single phase faults, each of 150 ms duration, within 31 seconds.

(2) The voltage tolerances apply to frequency tolerances as specified in Annexure 5.

(3) Routine and prototype response tests must be carried out to demonstrate capabilities as indicated in item 5(10) in Annexure 4.

On load tap changing for generating unit step-up transformers

58. (1) All generating unit step-up transformers must have on-load tap changing which can be remotely controlled.

(2) The range for the on-load tap change contemplated in subcode (1) must be agreed between the transmission company and the generator.

Emergency unit capabilities

59. All generators must specify the capabilities of their units for providing emergency levels 1 and 2 support under abnormal power system conditions as contemplated in code 178.

Facility for independent generator action

60. (1) Frequency control under system island conditions must revert to the power stations as the last resort, and units and associated plant must be equipped to handle such situations.

(2) The required control range is from 49 Hz to 51 Hz.

Automatic under-frequency starting

61. (1) It may be agreed with the system operator that a unit that is capable of automatically starting within 10 minutes must have automatic under-frequency starting.

(2) This starting must be initiated by frequency-level facilities with settings in the range 49Hz to 50Hz as specified by the system operator.

Testing and compliance monitoring

62. (1) A generator must keep records relating to the compliance by each of its units setting out the information that the system operator reasonably requires for assessing power system performance including actual unit performance during abnormal conditions.

(2) Within one month after the end of June and December, a generator must review, and confirm to the system operator, compliance by each of the units of that generator with items 5(1) to (11) in Annexure 4 during the past six month period.

(3) A generator must conduct tests or studies to demonstrate that each power station and each generating unit complies with each of the requirements of this Chapter.

(4) If a new unit is installed after an outage occurs as a result of a compromise on any of the procedures contemplated in item 5(1) to (11) in Annexure 4, the generator must carry out tests on the new unit to demonstrate that the unit complies with the relevant procedure.

(5) The generator must continuously monitor its compliance with all the connection conditions of the Transmission Grid Code.

(6) A generator must submit to the system operator a detailed test procedure, emphasising system impact, for the relevant part of this Chapter prior to every test.

(7) If a generator determines, from tests or otherwise, that one of its units or power stations is not complying with one or more codes in this Chapter, then the generator must -

- (a) promptly notify the system operator of that fact;
- (b) promptly advise the system operator of the remedial steps it proposes to take to ensure that the relevant unit or power station can comply with this Chapter and the proposed timetable for implementing those steps;
- (c) diligently take remedial action that will ensure that the relevant unit or power station can comply with this Chapter;
- (d) regularly report in writing to the system operator on its progress in implementing the remedial action; and
- (e) after taking remedial action as contemplated in paragraph (a), demonstrate to the reasonable satisfaction of the system operator that the relevant unit or power station is then complying with this Chapter.

Non-compliance suspected by the system operator

63. (1) If at any time a system operator believes that a unit or power station is not complying with a code in this Chapter, the system operator must -

- (a) notify the relevant generator of the non-compliance; and
- (b) specify the code concerned and the basis for the belief.

(2) If the generator contemplated in paragraph (a) subcode (1) believes that the unit or power station is complying with the code contemplated in paragraph (b) of that subcode, the system operator and the generator must promptly meet to resolve their difference.

Unit modifications

64. (1) If a generator proposes to change or modify any of its units in a manner that -

- (a) could reasonably be expected to adversely affect the ability of that unit to comply with this Chapter; or
- (b) changes the performance, information supplied or settings,

the generator must submit a proposal notice to the system operator which -

- (i) contains detailed plans of the proposed change or modification;
- (ii) states when the generator intends to make the proposed change or modification; and
- (iii) sets out the proposed tests to confirm that the relevant unit as changed or modified operates in the manner contemplated in the proposal and can comply with this Chapter.

(2) If the system operator disagrees with the proposal submitted as contemplated subcode (1), the system operator may notify the relevant generator, and the system operator and the relevant generator must promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement.

(3) The generator must ensure that an approved change or modification to a unit or to a subsystem of a unit is implemented in accordance with the relevant proposal approved by the system operator.

(4) The generator must notify the system operator promptly after an approved change or modification to a unit has been implemented.

(5) The generator must confirm that a change or modification to any of its units as conforms to the relevant proposal by conducting the relevant tests, in relation to the connection conditions, promptly after the proposal has been implemented.

(6) Within 20 business days after any the tests contemplated in subcode (5) has been conducted, the relevant generator must provide the system operator with a report in relation to that test including test results of that test, where appropriate.

Equipment requirements

65. (1) Where the generator needs to install equipment that connects directly with transmission company equipment, the equipment must adhere to the transmission company design requirements as set out in Part 2 of this Chapter.

(2) The transmission company may require customers to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

Connection conditions for distributors and end-use customers

66. (1) The transmission company must offer to connect and, subsequent to the signing of the relevant agreements, make available a point of connection to any requesting distributor or end-use customer.

(2) A customer may request additional reinforcements to the transmission system over and above that which could be economically justified as contemplated in Part 3 of this Chapter.

(3) The transmission company must provide such reinforcements if the customer agrees to bear the costs, which must be priced according to the tariffs approved by the Board.

Power factor

67. (1) Distributors and end-use customers must take all reasonable steps to ensure that the power factors at the point of supply is at all times 0,85 lagging or better, unless otherwise agreed to in existing contracts between the participants.

(2) This requirement applies to each point of supply individually for customers with more than one point of supply.

(3) A leading power factor must not be acceptable, unless specifically agreed to in writing.

(4) Should the power factor be less than the said limit during any 10 demand-integrated half hours in a single calendar month, the participants must co-operate in determining the plans of action to rectify the situation.

(5) Overall lowest cost solutions must be sought.

Protection

68. (1) Each participant must take all reasonable steps to protect its own plant.

(2) The system operator protection requirements, with which the customers must interface, are described in code 86.

(3) The detailed protection applications, insofar as the equipment of one participant may have an impact on the other, must be agreed to in writing by the relevant participants.

(4) Distributors who have customers connected directly to the transmission substations are responsible for ensuring that the customers comply with the relevant protection standards.

(5) The participants must co-ordinate protection to ensure proper grading and protection coordination.

Fault levels

69. (1) Minimum fault levels at each point of supply must be maintained by the

transmission company under normal operating conditions to ensure compliance with the relevant quality of supply standards and to ensure correct operation of the protection systems.

(2) The transmission company must liaise with customers in accordance with the process set out in codes 133 to 162 on how fault levels are planned to change and best overall solutions when equipment ratings become inadequate.

(3) Overall lowest cost solutions must be sought and a joint impact assessment must be done covering all aspects.

(4) The transmission company must communicate the potential impact on safety of people when equipment ratings are exceeded.

(5) The system operator must bi-annually or when substantial deviations have taken place, publish updated minimum and maximum normal operating fault levels for each point of supply.

(6) The customer must ensure his equipment is capable of operating at the specified fault level ranges.

(7) If equipment fault level ratings are or will be exceeded, the customer must promptly notify the transmission company.

(8) The transmission company must seek overall lowest cost solutions to address fault level problems.

(9) Corrective action must be at the cost of the relevant asset owner.

Distributor or end-use customer network performance

70. (1) If the distributor or end-use customer network performance falls below acceptable levels and affects the quality of supply to other customers or causes direct or indirect damage to the transmission company equipment, the process for dispute resolution set out in code 18 read with code 15 must be followed.

(2) Acceptable network performance must be -

- (a) performance comparable to benchmarks for similar networks;
- (b) performance that complies with the transmission company operating and maintenance procedures at that substation; and
- (c) performance that complies with the minimum agreed standards of quality of supply, as contemplated in code 71.

(3) If a distributor or end-use customer is aware that the network performance of the distributor or end-use customer may not comply with subcode (2), the distributor or end-use customer as the case may be must take reasonable steps, at own cost, to overcome the shortcomings by -

- (a) improving line maintenance practices;
- (b) improving protection and breaker operating times;
- (c) replacing the said equipment if necessary;
- (d) installing additional network breakers;

- (e) changing operating procedures; and
- (f) installing fault-limiting devices if the number of faults cannot be reduced.

(4) The steps contemplated in subcode (3) must be effected in consultation with the transmission company on both the technical scope and the time frame.

(5) Where quality of supply standards is transgressed, the parties must co-operate and agree in determining the root causes and plans of action.

Delivered quality of supply of transmission company

71. (1) Quality of supply is -

- (a) a shared responsibility between the transmission company and its customers; and
- (b) based on Namibian Quality of Supply and Service Standards as agreed with all stakeholders.

(2) The transmission company must agree in writing with its customers, for every point of supply, on the following quality of supply parameters, taking local circumstances, historical performance and the relevant standards into account:

- (a) interruption performance;
- (b) voltage regulation performance;
- (c) dip performance;
- (d) total harmonic distortion performance;
- (e) flicker performance;
- (f) unbalance performance; and
- (g) customer responsibilities in terms of harmonic current injection, unbalanced currents and addition of voltage dips to the network.

(3) A reasonable time period for monitoring performance must be allowed before performance is agreed to for the first time in terms of interruptions and dips.

(4) The time period contemplated in subcode (3) is three years unless otherwise agreed.

(5) For harmonic voltages and voltage unbalance, performance can be monitored after one week if measurements are done.

(6) Where a transmission company fails to meet the agreed upon quality of supply parameters contemplated in subcode (2)(b), the transmission company must take reasonable steps at own cost to overcome the shortcomings, by -

- (a) improving line maintenance practices;
- (b) improving protection and breaker operating times;
- (c) replacing the said equipment if necessary;

- (d) installing additional network breakers;
- (e) changing operating procedures; or
- (f) installing fault-limiting devices if the number of faults cannot be reduced.

(7) The steps contemplated in subcode (6) must be effected in consultation with the customer on both the technical scope and the time frame.

Equipment requirements

72. (1) Where a distributor or end-use customer needs to install equipment that connects directly with transmission company equipment in transmission substations, the equipment must adhere to the transmission company technical design requirements contemplated in codes 74 to 85 inclusive.

(2) The transmission company may require customers to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

(3) A distributor or end-use customer who intends to install a new series capacitor or modify the size of an existing series capacitor must, at own expense and according to the requirements of the transmission company, arrange for sub synchronous resonance, harmonic and protection coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any generator.

PART 2

TRANSMISSION SYSTEM TECHNICAL REQUIREMENTS

Purpose of transmission company technical design requirements

73. The purpose of the transmission company technical design requirements contemplated in codes 74 to 85 inclusive, is to document the design and other technical standards that the transmission company must adhere to.

Equipment design standards

74. (1) Primary substation equipment must comply with International Electro-technical Commission (IEC) specifications.

(2) The application of the specifications contemplated in subcode (1) must cater for local conditions including increased pollution levels and must be determined by or in consultation with the customer.

(3) The transmission company must design, install and maintain equipment in accordance with relevant electricity industry standards.

(4) Customers may require the transmission company to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

Clearances

75. Clearances must comply with relevant electricity industry standards.

Current Transformer (CT) and Voltage Transformer (VT) ratios and cores

76. Current Transformer and Voltage Transformer ratios and cores must be determined

by or in consultation with the transmission company.

Standard busbar arrangements and security criteria

77. Substations on the transmission system must be configured in accordance with code 78 and 79.

Transmission substation standard busbar arrangements

78. (1) The reliability and availability of the transmission system is dependent on, but not limited to -

- (a) transmission system lines;
- (b) transformers;
- (c) other primary and secondary plants; and
- (d) the busbar layout.

(2) When planning the transmission system, the transmission company must prudently assess the busbar layout contemplated in subcode (1)(d) and assess what the busbar layout can do for the reliability and availability of the supply of the customer.

(3) When planning substation design, the transmission company must base the standard busbar arrangement on providing one busbar zone for every main transformer line normally supplying that busbar.

(4) A transmission company must consider the local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required busbar redundancy.

(5) The system reliability criteria set out in code 138 must also be adhered to in addition to subcodes (1) to (4).

Use of bypasses

79. (1) Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability.

(2) The bypass with single busbar selection must be used at 220 kV on single line radial feeds to provide continuity of supply when maintaining the line breakers.

(3) The bypass with double busbar selection must be used on new 400 kV, 330 kV lines and 220 kV lines where justified.

Motorised isolators

80. To provide motorised isolators at new substations -

- (a) all 400 kV, 330 kV and 220 kV isolators must be motorised at new substations; and
- (b) isolators of 132 kV and below must be specified on individual merit, taking into

account importance ranking, cost and remoteness.

Earthing isolators

81. Earthing isolators must be provided at new substations where the fault level is designed for 20 kA and above.

Busbar protection Current Transformers (CT's)

82. (1) For phase 3 busbar protection schemes, single sets of Current Transformers, including 3 CT's instead of 6 CT's, must be used on bus couplers and bus section breakers to reduce the probability of a double bus zone outage for a CT fault on a bus coupler or bus section breaker.

(2) At power station, overlapped bus zones must be retained to ensure fastest possible clearance of busbar faults.

Tele-control

83. (1) Either participant may be permitted to have tele-control equipment in the substations, yards or buildings of the other party, to perform agreed monitoring and control and access must be provided to the tele-control equipment.

(2) Distributors must have reliable Supervisory Control and Data Acquisition (SCADA) facilities including telecommunications, computers and remote terminal units for the distribution system connected directly to the transmission system, to provide the necessary response where system conditions require.

Transformer tap change

84. (1) The transmission company must install automatic tap changing facilities on all new transformers.

(2) Transformers used in the transmission system at 220kV or more are normally not on automatic tap change and transformers supplying a customer are usually on automatic tap change.

(3) Voltage levels, sensitivity and time settings and on or off auto tap changing must be determined by the -

- (a) system operator in consultation with the customer; and
- (b) transmission company.

Substation drawings

85. The following set of drawings must be made available by the respective asset owners for all points of supply, if required by the other party for the purposes of connection:

- (a) station electric diagram;
- (b) key plan;
- (c) bay layout schedules;
- (d) foundation, earth mat and trench layout;
- (e) steelwork marking plan;

- (f) security fence layout;
- (g) terrace, road and drainage layout;
- (h) transformer plinth;
- (i) general arrangement;
- (j) sections;
- (k) slack span schedule;
- (l) barrier fence layout;
- (m) security lighting;
- (n) floodlighting parameter sketch;
- (o) protection details; and
- (p) contour plan.

Protection requirements

86. (1) Codes 87 to 123 specify the minimum protection requirements for a transmission company as well as typical settings, to ensure adequate performance of the transmission system as experienced by the customers.

(2) The transmission company must at all times install and maintain protection installations that comply with the provisions of the codes contemplated in subcode (1).

(3) The transmission company must conduct periodic testing of equipment and systems to ensure and demonstrate that the equipment and systems are performing to the design specifications.

(4) Tests procedures must be according to the specifications of the manufacturer.

(5) The transmission company must make available to customers all results of test performed on equipment for reasonable requests.

(6) Protection schemes are generally divided into -

- (a) equipment protection; and
- (b) system protection.

Protection design standards for equipment (feeder protection: 220kV and above)

87. (1) New feeders must be protected by the Main 1 and Main 2 protection systems.

(2) The Main 1 and Main 2 protection systems must be fully segregated in secondary circuits.

(3) An additional earth fault function must be incorporated in the main protection relays or installed separately to alleviate possible deficiencies of distance relays in detection of high resistance faults.

Protection settings for equipment (feeder protection: 220kv and above)

- 88.** (1) The protection relays -
- (a) must provide reliable protection against all possible short circuits;
 - (b) must provide remote or local back up for not cleared busbar faults; and
 - (c) are not set to provide overload tripping.
- (2) Where specifically required, the feeder protection may be set, if possible, to provide remote back up for other faults as agreed upon with other participants.

Automatic reclosing for equipment (feeder protection: 220kV and above)

- 89.** (1) Automatic reclosing facilities must be provided on all feeders.
- (2) The system operator must decide on automatic reclosing selection based on real time system, environmental constraints and consultation with customers, with regard to equipment capabilities and in accordance with codes 90 to 93.
- (3) All automatic reclosing settings and methodology must be -
- (a) implemented by the transmission company; and
 - (b) made available by the transmission company to customers on request.

Automatic reclosing cycles (ARC) for equipment (feeder protection: 220kV and above)

- 90.** (1) Either of the following two automatic reclosing cycles for single phase faults must be used:
- (a) double attempt ARC cycle for persistent fault: 1ph fault – 1ph trip – 1ph ARC – 3ph trip – 3ph ARC – 3ph trip – lockout; or
 - (b) single attempt ARC cycle for persistent fault: 1ph fault – 1ph trip – 1ph ARC – 3ph trip – lockout.
- (2) The ARC cycle for a multiphase (mph) fault must be: mph fault – 3ph trip – 3ph ARC – 3ph trip – lockout.
- (3) On some lines the automatic reclosing is being switched off according to the following operational needs:
- (a) sporadically, when high risk of line fault is recognised, for live line work or to reduce breaker duty cycle where the condition of the breaker is questionable;
 - (b) periodically, during season of high fault frequency;
 - (c) permanently, on lines with the highest fault frequency throughout the year or on the request of the customers; or
 - (d) whenever an automatic reclosing could initiate a severe power swing or an Out-Of-Step condition in weakly interconnected systems.

Single phase automatic reclosing

91. (1) In most applications the dead time of single phase automatic reclosing is selected to one second but may differ for different system requirements.

(2) The closing of the breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the whole incident.

Three phase automatic reclosing (fast ARC)

92. (1) Fast automatic reclosing or the fast closing of the breaker without checking synchronism, is not used on the transmission system to avoid stress to the rotating machines at the power stations and at the plant of the customer but is available on protection panels and can be selected in case of an emergency such as when as a result of outages disturbance load or generation islands are interconnected via a single line.

(2) Despite subcode (1) the operating practice is to use only single phase automatic reclosing (fast by its nature) as a compromise between supply reliability and stress to the equipment.

Three phase automatic reclosing (slow ARC)

93. (1) The dead line charging (DLC) end is selected in line with the Table 1 in Annexure 6 based on fault level at the connected substations A and B.

(2) In most applications the dead time of slow automatic reclosing is selected to three seconds at dead line charging (DLC) end of the line.

(3) At the synchronising end of the line the automatic reclosing dead time is usually selected to four seconds.

(4) The close command will be issued only after synch-check is completed and this may take up to two seconds if synchronising relays are not equipped with direct slip frequency measurement.

(5) The breaker may take longer to close if its mechanism is not ready to close after initial operation at the time when the close command is issued.

(6) On the line between two power stations the dead time at the dead line charging (DLC) end should be extended to 25 seconds to allow the rotors oscillations of the generator to stabilise.

(7) The dead time on the synchronising end is then extended accordingly to 30 seconds.

(8) The synchronising relays are installed at both ends of the line to enable flexibility in automatic reclosing cycles and during restoration.

Power swing blocking

94. (1) New distance relays on the transmission system must be equipped with power swing blocking facility.

(2) All unwanted operations of distance relays during power swing conditions must be blocked on the transmission system.

Design standard: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)

95. (1) The feeders of 132 kV and lower must be protected by a single protection system, incorporating either distance or differential protection relays, unless otherwise agreed.

(2) Back up must be provided by definite time and inverse definite minimum time (IDMT) over-current and earth fault relays.

(3) The protection must be equipped with automatic reclosing.

(4) Synchronising relays must be provided on feeders that operate in “ring supplies” and are equipped with line voltage transformers.

Protection settings: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)

96. (1) Protection relays -

(a) must provide reliable protection against all possible short circuits;

(b) must provide remote and local back up for un-cleared busbar faults; and

(c) should not be set to provide overload tripping where measurements and alarms are provided on Supervisory Control and Data Acquisition (SCADA) system.

(2) In isolated applications where Supervisory Control and Data Acquisition (SCADA) system is not available, overload tripping will be provided.

(3) Where overload conditions are alarmed at control centres, it is the responsibility of the control centre to reduce load to an acceptable level as quickly as possible.

Automatic reclosing: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)

97. (1) The customer must determine automatic reclosing requirements.

(2) The system operator may specify additional automatic reclosing requirements for system security reasons, which could extend beyond the transmission company substations.

Tele-protection requirements

98. New distance protection systems must be equipped with tele-protection facilities to enhance the speed of operation.

Transformer and reactor protection

99. (1) The standard schemes for transformer protection comprise a number of systems, each designed to provide the requisite degree of protection for the following fault conditions:

(a) faults within the tank;

(b) faults on transformer connections;

(c) overheating;

(d) faults external to the transformer; and

(3) The transmission company must consider the application of the relays contemplated in codes 100 to 106 inclusive, in the design of the protection system.

Transformer Inverse Definite Minimum Time Earth Fault

100. The medium voltage earth fault protection is to discriminate with the feeder back-up earth fault protection for feeder faults

Transformer HV/MV Inverse Definite Minimum Time Over-Current

101. (1) The system operator requires that the inverse definite minimum time over-current (IDMT O/C) does not operate for twice transformer full load.

(2) Overloading of the transformer is catered for by the winding and oil temperature protection but network requirements may be such that subcode (1) cannot be applied and a mutually agreed philosophy may have to be used.

Transformer HV/MV instantaneous Over-Current

102. Transformer high voltage medium voltage instantaneous over-current (Transformer HV/MV instantaneous Over-Current) back-up protection caters for flash-overs external to the transformer on the HV side or MV side and should operate for minimum fault conditions (possibly as well for an Earth Fault condition). However, the overriding requirement is not to operate for through faults or for magnetising inrush current.

Transformer LV (tertiary) Inverse Definite Minimum Time /instantaneous Over-Current

103. This protection is to operate for external faults between the main delta winding of the transformer and the auxiliary transformer, but not for faults on the secondary side of the auxiliary transformer. The auxiliary transformer is protected by buchholz and temperature protection.

Transformer current differential protection

104. (1) Transformer current differential protection is the main transformer protection for earth fault and phase to phase faults.

(2) Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current with its attendant decaying offset.

Transformer high impedance restricted Earth Fault

105. Transformer high impedance restricted earth fault is an additional protection for the transformer differential relay to cater for earth faults close to the star point of the transformer winding, where phase to phase faults are most unlikely to occur.

Transformer thermal overload

106. Winding temperature and oil temperature relays, supplied by the manufacturer are used to prevent transformer damage or life time reduction due to excessive loading for the ambient temperature or during failure of the cooling system.

Transmission system busbar protection

107. Busbars must be protected by current differential protection (bus-zone) set to be as sensitive as possible for the in-zone faults and maintain stability for any faults outside the protected

zone, even with fully saturated current transformer.

Transmission system bus coupler and bus section protection

108. Bus-coupler and bus-section panels are equipped with over-current and earth fault protection.

Transmission system shunt capacitor protection

109. (1) All the new high voltage capacitor banks must be equipped with sequence switching relays to limit inrush current during capacitor bank energisation. Inrush reactors and damping resistors must also be employed to limit inrush current.

(2) The following protection functions must be provided for all types of protection schemes:

- (a) unbalanced protection with alarm and trip stages;
- (b) over-current protection with instantaneous and definite time elements;
- (c) earth fault protection with instantaneous and definite time sensitive function;
- (d) overload protection with inverse definite minimum time characteristic;
- (e) over-voltage with definite time;
- (f) circuit breaker close inhibit for 300 seconds after de-energisation; and
- (g) ancillary functions as indicated below.

Over-voltage protection

110. (1) Primary protection against high transient over-voltages of magnitudes above 140% must be provided by means of surge arrestors.

(2) To curtail dangerous, fast developing over-voltage conditions that may arise as a result of disturbance, additional over-voltage protection must be installed on shunt capacitors and feeders.

(3) Over-voltage protection on shunt capacitors is set to disconnect capacitor at 110% voltage level with a typical delay of 200 milliseconds to avoid unnecessary operations during switching transients.

(4) Over-voltage protection on the feeders is set to trip the local breaker at voltage level of 120% with a delay of one to two seconds.

Ancillary protection functions

111. (1) Protection systems are equipped with auxiliary functions and relays that enable adequate co-ordination between protection devices and with bay equipment.

(2) The transmission company must consider the functions contemplated in codes 112 to 116 inclusive, for all new protection system designs.

Breaker fail or bus trip

112. Each individual protection scheme is equipped with breaker fail or bus trip function

to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

Breaker pole discrepancy

113. (1) Breaker pole discrepancy protection compares, by means of breaker auxiliary contacts, state (closed or opened) of breaker main contacts on each phase.

(2) When breaker on one phase is in a different position than breakers on remaining phases a trip command is issued after time delay.

Breaker anti-pumping

114. (1) To prevent repetitive closing of the breaker in case of fault in closing circuits the standard Protection schemes provide breaker anti pumping timer.

(2) Circuit breakers are often equipped with their own anti pumping devices and the anti pumping function is duplicated.

Pantograph isolator discrepancy

115. The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarm.

Master relay

116. (1) Transformer and reactor protection schemes are equipped with latching master relay that require manual reset before the circuit breaker is enabled to close.

(2) The master relay is operated by unit protection that indicates possibility of internal failure.

System protection requirements (under-frequency load shedding)

117. (1) The actions taken on the power system during an under-frequency condition are set out in Chapter 4.

(2) Under-frequency load shedding relays must be installed in the interconnected power system as determined by the system operator in consultation with distributors and end-use customers.

(3) An asset owner must pay for the installation and maintenance of the relays referred to in subcode (2).

(4) The system operator must periodically test under-frequency relays.

(5) Distributors and end-use customers must submit to the system operator a written report of each test referred to in subcode (4) within a month of the test being done and in the format specified in code 230(2).

(6) The test referred to in subcode (4) must be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

System protection requirements (out of step tripping)

118. (1) The purpose for the out-of-step tripping protection is to separate power system in a situation where a loss of synchronous operation takes place between a unit or units and

the main power system.

(2) In a situation referred to in subcode (1), system separation is desirable to remedy the situation.

(3) Once the islanded system is stabilised it can be reconnected to the main system.

(4) The system operator must determine and specify the out-of step tripping functionality to be installed at selected locations by the transmission company.

System protection requirements (Under-voltage load shedding)

119. (1) Under-voltage load shedding protection schemes are used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic load shedding tripping of suitable loads is carried out to arrest the slide.

(2) The system operator must determine and specify the under-voltage load shedding functionality to be installed at selected locations by the transmission company.

System protection requirements (sub-synchronous resonance protection)

120. (1) The sub-synchronous resonance condition may arise on a power system where a generator is connected to the main power system through long series compensated transmission system lines.

(2) The potential for unstable interaction is sensitive to system topology and is greater with the higher degree of compensation and larger thermal turbo-generators are employed.

(3) The sub-synchronous resonance condition is addressed either through protection or mitigation and if through -

(a) protection -

(i) a suitable relay must be deployed as part of the turbo-generator protection that will lead to the unit disconnection on detection of the sub-synchronous resonance condition; and

(ii) the protection does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance; or

(b) mitigation, the mitigation -

(i) acts to reduce or eliminate the resonant condition; and

(ii) is needed only under conditions when it is desirable or essential to continue operation when the power system is at or near a resonant condition.

(4) A new generator must liaise with the transmission company regarding sub-synchronous resonance protection studies.

(5) Least-cost solutions must be determined by the transmission company in accordance with code 147 and implemented by the relevant asset owner.

System protection requirements (protection against near 50 Hz resonance)

121. (1) Due to the length of the transmission system network in Namibia and due

to the relatively low load conditions, a near 50 Hz resonance may arise on the transmission system network.

(2) Adequate reactive compensation for purposes of subcode (1) need to be installed on the transmission system and the influence of the system operator and clients on this near 50 Hz resonance needs to be reduced.

(3) The transmission company must ensure that the near 50 Hz resonance is catered for in any old or new networks.

System protection requirements (protection settings impact on network stability (dynamic stability))

122. Minimum clearance times for protection in distributor or end-use customer networks will be determined on a case by case basis in order to ensure dynamic stability of the transmission system.

Protection system performance monitoring

123. (1) To maintain high level of protection performance and long term sustainability, the Transmission company must monitor protection performance.

(2) Each protection operation must be investigated for its correctness based on available Information.

(3) The transmission company must provide a report to customers affected by a protection operation when requested to do so.

Nomenclature

124. All safety terminology must comply with the transmission company operating regulations for high voltage systems.

PART 3

TRANSMISSION SYSTEM PLANNING AND DEVELOPMENT

Transmission system planning and development

- 125.** (1) Codes 126 to 155 sets out the -
- (a) technical, design and economic criteria and procedures to be applied by the transmission company in the planning and development of the transmission system and to be taken into account by customers in the planning and development of their own systems; and
 - (b) information to be supplied by customers to the transmission company, and information to be supplied by the transmission company to customers.
- (2) The development of the transmission system, will arise for a number of reasons including, but not limited to -
- (a) a development on a customer system already connected to the transmission system;
 - (b) the introduction of a new transmission system substation or point of connection or the modification of an existing connection between a customer and the transmission

system;

(c) the cumulative effect of a number of the developments referred to in paragraphs (a) and (b) by one or more customers; and

(d) the need to reconfigure, decommission or optimise parts of the existing network.

(3) The development of the transmission system as contemplated in subcode (2) may involve work -

(a) at a substation where a plant or apparatus of a customer is connected to the transmission system;

(b) on transmission system lines or other facilities which join the substation referred to in paragraph (a) to the remainder of the transmission system; or

(c) on transmission system lines, transmission system substations or other facilities at or between points remote from that substation.

(5) The time required for the planning and development of the transmission system will depend on -

(a) the type and extent of the necessary reinforcement or extension work;

(b) the need or otherwise for statutory planning consent;

(c) the associated possibility of the need for public participation; and

(d) the degree of complexity in undertaking the new work while maintaining satisfactory security and quality of supply on the existing transmission system.

Planning process

126. The transmission company must follow a planning process divided into major activities as follows:

(a) needs identification;

(b) formulation of alternative options to meet this need;

(c) studying these options to ensure compliance with agreed technical limits, and justifiable reliability and quality of supply standards;

(d) costing these options on the basis of present-day capital costs and using appropriate net discount rates, establish the net present cost of each option;

(e) determining the preferred option;

(f) building a business case for the preferred option using acceptable justification criteria; and

(g) requesting approval of preferred option and initiating execution.

Identification of need for transmission system development

127. The transmission company must source relevant data from relevant national planning studies, specific customer information, governmental and customer development plans to establish the needs for network strengthening.

Forecasting demand

128. (1) The transmission company is responsible for producing the transmission system demand forecast for the next five years and updating it annually and for estimating the load forecast for the next 10 years.

(2) The transmission system demand forecast must be determined for each point of supply.

(3) Generation and import capacity plans must be used to obtain the annual generation patterns.

(4) To forecast the maximum demand megawatt for each transmission system substation, the transmission company must -

(a) use distributor and end-use customer load forecasts; and

(b) reconcile final loads with data from various sources.

(5) Load forecasts must be adjusted at various levels, by making use of diversity factors determined from measurements and calculations, to line up with the higher-level data.

(6) All distributors and end-use customers must annually, by end October, supply their five year ahead load forecast data and an estimate for the 10 years ahead demand as detailed in Chapter 6.

Technical limits and targets for planning purposes

129. (1) The limits and targets against which proposed options are checked by the transmission company must include technical and statutory limits which must be observed and other targets which indicate that the system is reaching a point where problems may occur.

(2) If technical or statutory limits are not achieved, alternative options shall be evaluated.

(3) If targets are not achieved, some options may be still acceptable as per the investment criteria.

Voltage limits and targets

130. (1) The technical and statutory voltage limits are as set out in Table 2 of Annexure 3.

(2) The standard voltage levels are as set out in Table 3 of Annexure 3.

(3) The target voltages for planning purposes are as set out in Table 4 of Annexure 3.

Other targets for planning purposes

131. The other targets for planning purposes are as set out in codes 132 to 137 inclusive.

Transmission system lines

132. (1) Thermal ratings of standard transmission system lines must be determined and updated from time to time.

(2) The temperatures used are 90°C for aluminium conductor steel reinforced lines providing a firm supply, under single contingencies and 75°C for lines of copper or aluminium alloy or aluminium conductor steel reinforced lines not providing a firm supply.

(3) The thermal ratings must be used as an initial check of line overloading.

(4) If the limits of the thermal ratings are exceeded the situation must be investigated as it may be possible to defer strengthening depending on the actual line and on local conditions.

Transformers

133. (1) Standard transformer ratings must be determined and updated from time to time using International Electro-technical Commission (IEC) specifications.

(2) The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors.

(3) If target loads are exceeded, the specific situation must be assessed as it may be possible to defer adding extra transformers, depending on the actual transformer and on load conditions.

Series capacitors

134. (1) With the system healthy, the maximum steady state current should not exceed the rated current of the series capacitor.

(2) IEC 143 standards call for cyclic overload capabilities as follows:

(a) 8 hours in a 12-hour period, 1.1 times rated current;

(b) ½ hour in a 6 hour period, 1.35 times rated current; and

(c) 10 minutes in a 2 hour period, 1.5 times rated current.

(3) Despite subcode (2) the transmission company may require an occasional over-current rating of two hours once per year 1.3 times rated current.

(4) The particular rating to be used must match the duration of the contingency with the required overload capability.

(5) Duration of contingency will depend on ability to pick up generation or shed load and the load profile.

(6) If a transmission company intends to install a new series capacitor or modify the size of an existing series capacitor, the transmission company must at own expense and according to its requirements, arrange for sub synchronous resonance, harmonic and protection coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any generator.

Shunt reactive compensation

135. (1) Shunt capacitors must be able to operate at 30 percent above their nominal rated current at U_n to allow for harmonics and voltages up to U_m .

(2) Reactive compensation, whether new or modified, may cause harmonic resonance problems.

(3) A participant wishing to install or modify reactive power compensation must at his expense arrange for harmonic resonance studies to be conducted.

(4) If the studies referred to in subcode (2) indicate possible harmonic resonance conditions which could impact on the transmission system the participant must inform the system operator before proceeding with the installation or modification.

Circuit breakers

136. (1) Normal and fault current ratings for standard switchgear are determined and updated from time to time.

(2) The ratings contemplated in subcode (1) and the following limits specified for circuit breakers must not be exceeded:

(a) Single-phase breaking current, 1.15 times three phase fault current; or

(b) Peak making current, 2.55 times three phase rms fault current.

Secondary automatic reclosing cycle current during single-phase re-closing

137. The secondary automatic reclosing cycle current must not exceed:

(a) 20 amps rms with recovery voltage of 0.4 pu; or

(b) 40 amps rms with recovery voltage of 0.25 pu.

Reliability criteria for planning purposes

138. (1) A system cannot be made 100% reliable as planned, forced outages of components will occur and multiple outages are always possible, despite having a very low probability of occurrence.

(2) From an economic point of view optimum reliability is obtained when the cost involved in reducing the load not supplied by one kW is just equal to the value of this unsupplied kW to the economy or to the specific customer involved.

(3) The appropriate degree of reliability depends on the probability of loss of supply and the probable amount of load not supplied when an outage does occur.

(4) The transmission company must formulate long-term plans for expanding or strengthening the transmission system on the basis of the justifiable redundancy.

Contingency criteria for planning purposes

139. (1) A system meeting the n-1 or n-2 contingency criterion must comply with the limits referred to in code 130.

(2) For contingencies under various loading conditions it must be assumed that appropriate, normally-used, generating plant is in service to meet the load and provide spinning reserve.

(3) The availability of the Ruacana Power Station will be taken into account for all load flow studies.

(4) A generation condition at Ruacana will not be one of the base cases used in planning studies.

(5) For the more probable n-1 network contingency the most unfavourable generation pattern within the limitations referred to in subcodes (1) to (4) must be assumed, while for the less probable n-2 network contingency an average pattern must be used.

(6) More details of load and generation assumptions for load flow studies are set out in code 140.

(7) The generation assumptions for the n-1 and n-2 network contingencies do not affect the final justification to proceed with investments, but merely check that the backbone of the network is still sufficient to meet an n-1 or n-2 contingency.

Integration of power stations

140. When planning the integration of power stations the criteria contemplated in codes 141 to 145 inclusive, applies.

Power stations of less than 1000 MW

141. (1) With all connecting lines healthy, it must be possible to transmit the total output of the power station to the system for any system load condition.

(2) If the local area depends on the power station for voltage support, connection must be done with a minimum of two lines.

(3) Transient stability must be maintained following a successfully cleared single phase fault where economically justifiable.

(4) If only a single line is used it must be able to be selected to alternative busbars and be able to go on to bypass at each end of the line

Power stations of more than 1000 MW

142. (1) With one connecting line out of service (n-1) it must be possible to transmit the total output of the power station to the system for any system load condition

(2) With the two most onerous line outages (n-2) it must be possible to transmit 83% of the total output of the power station to the system

Transient stability

143. (1) Transient stability must be retained for the following conditions -

(a) a three-phase, line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous power station loading condition;

- (b) a single phase fault cleared in bus strip times, with the system healthy and the most onerous power station loading condition; or
- (c) a single-phase fault, cleared in normal protection times, with any one line out of service and the power station loaded to average availability.

(2) The conditions contemplated in subcode (1) apply only to power stations larger than 1000 MW, for power stations smaller than 1000 MW, the conditions will only apply where it is economically justifiable.

(3) A transmission company bears the cost to ensure transient stability and must recover the costs as per the approved tariff methodology.

(4) Despite subcode (3), a generator bears the cost to ensure transient stability if the optimum solution, as determined by the transmission company, results in unit or power station equipment to be installed.

Busbar arrangements

144. Busbar layouts must allow for selection to alternative busbars and the ability to go on to bypass, and not more than 1000 MW of generation must be connected to any bus section, even with one bus section out of service.

Information required

145. To enable the transmission company to successfully integrate new power stations, detailed information is required per unit and power station, as contemplated in Chapter 6.

Criteria for network investments

146. (1) The planning limits, targets and criteria form the basis for evaluation of the long-term development of the transmission system.

(2) The transmission company must -

- (a) only invest in the transmission system when the required development meets the approved investment criteria specified in subcode (5); and
- (b) invest as contemplated in paragraph (a) if the development meets the approved criteria, but the transmission company may agree with affected customers to waiver certain investments.

(3) Any one of the investment criteria set out in subcodes 4 and 5, each applicable under different circumstances, can be applied.

(4) Calculations will assume a typical project life expectancy of 25 years except where otherwise dictated by plant life or project life expectancy.

(5) The following key economic parameters must have a Board approved process of being established:

- (a) discount rate; and
- (b) Cost of unserved energy.

Least economic cost criteria

147. (1) The least economic cost criteria may be used -

- (a) when investments are made in terms of improved supply reliability or quality; or
- (b) to determine or verify the desired level of network or equipment redundancy.

(2) The least economic cost criteria requires -

- (a) the determination of the cost of poor network services including the cost of interruptions, load shedding, network constraints and poor quality of supply; and
- (b) statistical analysis of network outages.

(3) The least-cost investment criterion equation to be satisfied can be expressed as:
 Value of improved quality of supply to customers > Cost to the service provider to provide improved quality of supply.

(4) If a project is proposed and pursuant to subcode (1)(a) a service provider uses the equation in subcode (2), the service provider should not invest in the proposed project if the value of the improved quality of supply to the customer is less than the cost to the service provider to improve the quality of supply.

(5) Equation above can be stated differently as: Annual value (N\$/kWh) x Reduction in expected energy not served to Consumers (kWh) > Annual cost to the service provider to reduce expected energy not served (R).

(6) For purposes of subcode (4) -

- (a) the reduction in expected energy not served is calculated on a probabilistic basis based on the improvements derived from the investments; and
- (b) the cost of unserved energy is a function of -
 - (i) the type of load;
 - (ii) the duration and frequency of the interruptions;
 - (iii) the time of the day the interruptions referred to in subparagraph (ii) occur;
 - (iv) whether notice is given of the impending interruption;
 - (v) the indirect damage caused;
 - (vi) the start-up costs incurred by the consumers;
 - (vii) the availability of customer back-up generation; and
 - (viii) many other factors.

Cost reduction investments

148. (1) Proposed expenditure which is intended to reduce the costs -

- (a) to service providers, of but not limited to -
 - (i) shunt capacitor installations;
 - (ii) telecommunication projects and telecommunication replacement equipment which reduce costs; and
 - (iii) external telephone service expenses and maintenance costs; or
- (b) of losses or other ancillary services,

should be evaluated in the manner set out in subcode (2).

- (2) For purposes of the evaluation contemplated in subcode (1) -
 - (a) it is necessary to calculate the net present value of the proposed investment using the discounted cash flow method;
 - (b) the calculation referred to in paragraph (a) should be done by considering all cost reductions including savings in system losses, as positive cash flows off-setting the required capital expenditure;
 - (c) sensitivity analysis is required with respect to the -
 - (i) amount of capital expenditure, including estimated contingency amount;
 - (ii) annual average incremental cost of generation, where appropriate; and
 - (ii) future load growth scenarios; and
 - (d) if the calculation under paragraphs (a) and (b) or the sensitivity analysis under paragraph (c) results in a positive net present value, the investment is justified over the expected life of the proposed new asset.

Statutory or strategic investments

149. (1) Decisions on statutory or strategic investments need to be taken in order to encourage development in Namibia.

- (2) Projects relating to statutory or strategic investments include the following:
 - (a) investments formally requested by government, including investments that will allow Namibia to become more self-sufficient in electricity supply and issues pertaining to the electrification of Namibia;
 - (b) increased connection with neighbouring countries and SAPP requirements to allow the electricity industry of Namibian access to other markets;
 - (c) projects necessary to meet environmental legislation, for example the construction of oil containment dams;
 - (d) expenditure to satisfy the requirements of the Labour Act, 2007 (Act No. 11 of 2007) and specifically the Regulations relating to Health and Safety of Employees at Work published under Government Notice No. 1617 of 1 August 1997;
 - (e) possible compulsory contractual commitments; or

(f) servitude acquisition.

(3) Subcode (2)(d) is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission.

(4) Subcode (2) must not be used for justifying projects that are not of economic benefit.

Development investigation reports

150. (1) The transmission company must compile, before any development of the transmission system is approved, a detailed development investigation report.

(2) The report referred to in subcode (1) must be used as the basis for making the investment decision and must as a minimum contain the following elements:

- (a) a description of the problem or request;
- (b) alternatives considered, including non-transmission or capital;
- (c) an evaluation of the long-term costs or benefits of each alternative contemplated in paragraph (b); and
- (d) detailed techno-economic justification of the selected alternative according to the approved investment criteria.

Transmission system master plan

151. (1) The transmission company must annually publish a five year ahead network expansion plan, indicating the major capital investments planned.

(2) The transmission company must base the network expansion plan contemplated in subcode (1) on -

- (i) all customer requests received at the time of planning;
- (ii) network load forecasting; and
- (iii) projects initiated by the transmission company.

Mitigation of network constraints

152. (1) A transmission company must regularly review and resolve network constraints

(2) A transmission company must put in place around each constraint economically optimal plans involving investment, the purchase of the constrained generation ancillary service or other solutions.

Interfacing between participants

153. A transmission company must ensure regular interfacing with customers, regarding network development, with the objective to achieve overall optimal plans that ensure economically efficient investment.

Special customer requirements for increased reliability

154. (1) If a customer requires a more reliable connection than the one provided by the transmission company and the customer is willing to pay the total cost of providing the increased reliability, the transmission company must meet the requirements at the lowest overall cost.

(2) Customers paying extra for reliability should be able to recoup some of the expenses from other customers.

(3) The transmission company must include details regarding recovery of direct costs in its connection agreement with its customers, distributors or end-use customers.

Network maintenance

155. (1) A participant -

- (a) must operate and maintain the equipment owned by the participant; and
- (b) bears the costs of the operation and maintenance contemplated in paragraph (a) unless the participant proves that the equipment referred to in that paragraph was damaged by the negligent act or omission of another participant or a participant who is not -
 - (i) the owner of the equipment; or
 - (ii) an agent or employee of the owner referred to in subparagraph (i),

in which case the participant who is responsible for the damage is liable for the costs of repairing the damage.

(2) Participants must monitor the performance of their plant and take appropriate action where deteriorating trends are detected.

CHAPTER 4
TRANSMISSION SYSTEM OPERATIONS

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

Operation of interconnected power system

156. (1) The system operator is responsible for the safe and efficient operation of the interconnected power system.

(2) The system operator must operate the interconnected power system in accordance with the provisions of this code.

(3) All participants must co-operate in setting up operational procedures under the direction of the system operator to ensure proper operation of the interconnected power system.

(4) The system operator has ultimate authority and accountability for the operation of the interconnected power system.

(5) SAPP and other international tie-line operations must be governed by the SAPP and related agreements.

System operator obligations

157. The system operator is responsible for the -
- (a) system reliability and safety contemplated in code 158;
 - (b) system security contemplated in code 159; and
 - (c) operational measures contemplated in code 160.

System reliability and safety

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

(2) Power transfers as determined by the energy market or scheduling arrangements, and other transfers as far as feasible, must be adjusted as required to achieve or restore reliable interconnected power system operation.

(3) Voltage control, operating on the interconnected power system and security monitoring must be co-ordinated on a system - wide basis in order to ensure safe, reliable, and economic operation of the interconnected power system.

(4) During or after a system disturbance high priority must be given to keeping all synchronised units -

- (a) running and connected to the interconnected power system; or
- (b) islanded on their own auxiliaries,

in order to facilitate system restoration.

(5) Black start services must be provided as available from units.

(6) The system operator must make all reasonable endeavours to retain international interconnections unless it becomes evident that continued parallel operation of the affected parts of the interconnected power system would jeopardise the remaining system or damage equipment.

(7) Should it become unsafe to operate units in parallel with the system when critical levels of frequency and voltage result on the interconnected power system from a disturbance, the separation or safe shut down of units must be done in such a way as to minimize the time required to resynchronise and restore the system to normal.

(8) In the event of a system separation the system operator must ensure that the part of the interconnected power system with a generation deficit must automatically remove sufficient load to permit early recovery of voltage and frequency so that system integrity may be re-established.

(9) Customer load must be shed for a reasonable period of time rather than risking the possibility of a cascading failure or operating at abnormally low frequency or voltage for an extended period of time.

(10) A system operator of an interconnected power system may request that the national system operator takes any available action to increase or decrease the active power transfer into or out of the local power system by the way of emergency assistance.

System security

159. (1) The interconnected power system must be operated as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe double contingency.

(2) Multiple outages of a credible nature must be examined and whenever practical the interconnected power system must be operated to protect the interconnected power system against instability, uncontrolled separation and cascading outages.

(3) The system operator is responsible for efficient restoration of the transmission system after supply interruptions.

(4) The system operator must operate and maintain primary and emergency control centres and facilities to ensure continuous operation of the interconnected power system.

Operational measures

160. (1) Operating instructions, procedures, standards and guidelines must be established to cover the operation of the interconnected power system under all system conditions.

(2) The interconnected power system must be operated within defined technical standards and equipment ratings.

(3) The system operator must manage constraints on the transmission system through the determination of operational limits and the purchase of the constrained generation ancillary service.

(4) To achieve a high degree of service reliability, the system operator must ensure adequate and reliable communications between all control centres, power stations and substations.

(5) Communication facilities to be provided and maintained by customers are specified in code 217.

(6) The system operator is responsible for the determination of the transmission system protection philosophy, as contrasted to equipment protection, by means of applicable analytical studies.

(7) The system operator must determine, and review on a regular basis, relay settings for main and back-up protection on the interconnected power system.

Scheduling of generation and ancillary services

161. (1) The system operator must provide a day-ahead demand forecast for the interconnected power system.

(2) The single buyer must provide the system operator with the daily 24 hours day-ahead energy schedule from 16:00CAT each day.

(3) Should a deviation exist between the scheduled and actual load conditions the system operator is responsible for taking remedial action.

(4) A system operator is responsible for executing the energy schedule.

(5) A single buyer is responsible for scheduling ancillary services.

(6) A system operator is responsible for executing ancillary services.

(7) Rescheduling of generation and ancillary services during unplanned events must be undertaken by the system operator on the basis of rules provided by the single buyer.

Ancillary services

162. (1) The system operator is responsible for the technical specification and execution of all short term reliability services for the interconnected power system.

(2) The short term reliability services referred to in subcode (1) include -

(a) restoration;

(b) the balancing of supply and demand;

(c) the provision of quality voltages; and

(d) the management of the real-time technical risk.

(3) Suitable ancillary service levels for the following year must be calculated annually.

(4) Reliability targets must be selected to minimise the sum of the cost to the transmission company of providing the reliability plus the cost to the customer of limited reliability.

(5) The single buyer is responsible for procuring the required ancillary services that are economically efficient and needed to provide the required reliability.

(6) The acquisition of ancillary services must take place on a non-discriminatory basis.

Operating reserves

163. (1) Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand.

(2) For purposes of subcode (1) there must be a spinning reserve, regulating reserve and quick reserve.

Spinning reserve

164. (1) The requirement is to keep the frequency above 49.5 Hz following all credible single contingency losses.

(2) The current requirement is defined by the Agreement Between Operating Members of the Southern African Power Pool.

Quick reserve

165. (1) A quick reserve -

(a) is a less frequently used reserve and is used when the interconnected power system is not in a normal condition;

(b) can be used for supply and demand balancing, network stability and voltage constraints; and

- (c) must be activated, on request, within 10 minutes and must be sustainable for two hours.
- (2) A minimum power as defined by the Agreement Between Operating Members of the Southern African Power Pool is to be accepted for this reserve.
- (3) Individual contracts may be aggregated into blocks executed as set out in Table 2 of Annexure 12.
- (4) If individual contracts are aggregated as contemplated in subcode (3), each aggregated block must be contracted as one block.
- (5) The quick reserve referred to in subcode (1) must also be under direct control from the system operator control centre.
- (6) The requirements stated in subcodes (1) to (5), are due to the need to take quick action when abnormal conditions prevail on the system.

Regulating reserve

- 166.** (1) The regulating reserve is used -
- (a) for second-by-second balancing of supply and demand; and
 - (b) to restore instantaneous reserve within 10 minutes of a disturbance.
- (2) The interconnected power system needs an amount of power as defined by the Agreement Between Operating Members of the Southern African Power Pool every hour to balance supply and demand and to keep the frequency and tie-lines within acceptable limits.
- (3) The payment for moving up and down on automatic generation control is made under the regulation and load following ancillary service under code 169.

Black start and islanding

- 167.** (1) Islanded units must be capable of running in the islanded state for at least two hours and of re-connecting to the network.
- (2) Units capable of islanding must -
- (a) offer service to the system operator; and
 - (b) be certified by the system operator and entitled to payment for the service referred to in paragraph (a).
- (3) To ensure optimal operation of the interconnected power system, the system operator may deploy network islanding schemes on the network, including an out-of-step tripping scheme.
- (4) The system operator must determine the minimum requirements for each black start supplier and ensure that the contracted suppliers are capable of providing the service.

Reactive power compensation and voltage control from units

- 168.** (1) Voltage control and the supply or consumption of reactive power is inter-related in the sense that the voltage is affected by changes in the reactive power flow.

(2) System stability depends on the voltage profile across the system.

(3) In view of subcodes (1) and (2), it is necessary from time to time to employ certain power stations to supply or consume reactive power whether or not they are producing active power, for the purpose of voltage control.

(4) The unit must be able to provide reactive power without having to produce or consume a large quantity of real power.

(5) The amount of reactive power must be controlled by the system operator through the energy management system or by telephone.

(6) When a unit is generating or pumping, reactive power supply is mandatory in the full operating range as specified in code 39.

Regulation and load following

169. (1) The regulation and load following service is the automatic matching of supply and demand in real time by increasing or decreasing the active power of units.

(2) The control system for matching of supply and demand is called automatic generation control and it can send a command every four seconds to increase or decrease output.

(3) The unit of measure for determining payment is the number of megawatts moved by the supplier of the service in the hour.

Technical requirements of regulation and load following

170. (1) The resources contracted for the service of regulation and load following under code 169, must operate under automatic generation control and must be able to alter their generation or load under direct control of automatic generation control to the performance requirements specified by the system operator.

(2) The requirement for the total capacity of regulation to be provided by the suppliers of the service of regulation and load following under code 169 is specified under regulation reserve in code 166.

(3) The requirement in subcode (2) is to meet the frequency and tie-line control standards as defined by the system operator and the Southern African Power Pool.

Near 50 Hz resonance control service

171. (1) Some plant may be required to run in synchronous condenser mode in order to add fault level to the transmission system to mainly assist with the shifting of the near 50Hz resonance in the Namibian network upwards from 50Hz.

(2) The near 50Hz resonance control service is an additional risk mitigation option for the Auas Static VAR Compensator.

(3) The plants are rewarded financially for the supply of a near 50Hz resonance control service.

Operational authority

- 172.** (1) The system operator has operational authority over the transmission system.
- (2) Operational authority for other networks lies with the respective asset owners.
- (3) Normal control of the various networks must be in accordance with the operating procedures agreed between the participants.
- (4) Unless otherwise provided in this Code, a participant may not be permitted to operate the equipment of another participant without the permission of that other participant.
- (5) Before a participant is permitted to operate the equipment of another participant the asset owner has the right to test and authorise the operating staff in accordance with his or her own standards before the permission is granted.
- (6) Despite subcode (1), participants retain the right to safeguard the health of their equipment.

Operating procedures

- 173.** (1) The system operator must develop and maintain operating procedures for -
- (a) the safe operating of the transmission system; and
- (b) assets connected to the transmission system.
- (2) The operating procedures referred to in subcode (1) must be adhered to by participants when operating equipment on the transmission system or connected to the transmission system.
- (3) Each customer is responsible for his or her own safety rules and procedures.
- (4) The system operator must ensure the compatibility with regard to the safety rules and procedures of all participants but if a dispute affecting the interpretation or application of safety rules and procedures should arise, the dispute must be resolved in accordance with the procedures specified by the system operator.
- (5) The Southern African Power Pool operating agreements apply in the case of operational liaison with all international power systems connected to the transmission system.

Operational liaison, permission for synchronisation

- 174.** (1) The system operator must sanction the switching, including shutting down and synchronising, of units and changing over of auxiliaries on all units.
- (2) If a participant experiences an emergency, the other participants must assist to an extent as may be necessary to ensure that the emergency does not jeopardise the operation of the networks or plant.
- (3) A customer must enter into an operating agreement with the system operator, if it is physically possible to transfer load or embedded generators from one point of supply to another by performing switching operations on the network of the customer.
- (4) The operating agreement under subcode (3) must cover at least the operational communication and notice period requirements and switching procedures for load transfers.

Emergency or contingency planning

- 175.** (1) The system operator must develop and maintain contingency plans to manage system contingencies and emergencies that are relevant to the performance of the interconnected power system.
- (2) The contingency plans under subcode (1) must -
- (a) be developed in consultation with all participants;
 - (b) be consistent with internationally acceptable utility practices; and
 - (c) include -
 - (i) under-frequency load shedding;
 - (ii) meeting disaster management requirements including the necessary minimum load requirements;
 - (iii) forced outages at all points of interface; and
 - (iv) supply restoration.
- (3) Emergency plans must allow for quick and orderly recovery from a partial or complete system collapse, with minimum impact on customers.
- (4) Emergency plans must comply with Southern African Power Pool agreements and guidelines.
- (5) All contingency or emergency plans must be periodically verified by actual tests to the greatest practical extent, as agreed by the parties, without causing undue risk or undue cost.
- (6) The costs of the tests referred to in subcode (5) must be borne by the respective asset owners.
- (7) The system operator, in consultation with all affected participants, must ensure the coordination of the tests referred to in subcode (5).
- (8) The system operator must specify minimum emergency requirements for distributor control centres, power station local control centres and substations to ensure continuous operation of their control, recording, enunciator and communication facilities.
- (9) Other participants must comply with the requirements of the system operator for contingency or emergency plans.
- (10) Automatic and manual load shedding schemes must be made available under the direction of the system operator.
- (11) The system operator must be responsible for determining all operational limits on the transmission system by means of the applicable analytical studies.
- (12) Load flow studies must be conducted regularly to determine the effect that various component failures would have on the reliability of the interconnected power system.
- (13) At the request of the system operator, distributors must perform related load flow studies on their part of the network and make the results available to the system operator.

System frequency and Area Control Error control under abnormal frequency or imbalance conditions

176. The system operator is responsible for the balancing of supply and demand in real time through the implementation of the energy schedules and utilisation of ancillary services.

Description of normal frequency or balancing conditions

177. (1) The control area is considered to be under normal frequency conditions when -

- (a) the immediate demand can be met with the available scheduled resources, including any expensive contingency resources;
- (b) the SAPP control performance criteria are not consecutively violated;
- (c) the frequency is within the range 49,5 to 50,5 Hz;
- (d) the interconnection is intact; and
- (e) there are no security and safety issues.

(2) The control area is considered to be under abnormal conditions if it is not in a normal condition as contemplated in subcode (1).

Operation during abnormal conditions

178. (1) When abnormal conditions occur, corrective action must be taken until the abnormal condition is corrected.

(2) The corrective action referred to in subcode (1) includes both supply-side and demand-side options.

(3) Where possible, warnings must be issued by the system operator on expected utilisation of any contingency resources.

(4) The system operator must have a designated person to refer to in periods of abnormal operation, particularly during emergencies.

(5) The order in which emergency resources are to be used may change from time to time.

(6) An updated list must be issued by the system operator.

(7) Termination of the use of emergency resources must occur as the plant shortage situation improves and after frequency has returned to normal.

(8) Automatic under-frequency systems must be kept armed at all times.

Independent action by participants

179. (1) Each participant must have the right to reduce or disconnect a point of connection under emergency conditions if it is necessary for the protection of life or equipment.

(2) If a participant considers it necessary to reduce or disconnect a point of connection as contemplated in subcode (1) the participant must give advance notice of the intended reduction or disconnection where possible and no financial penalties apply.

(3) During emergencies that require load shedding, the request to shed load must be initiated in accordance with agreed procedures.

(4) Following emergency operations necessary to protect the integrity of the interconnected power system or the safety of equipment and human life, the participants must work diligently towards removing the cause of the emergency and the supply must be reconnected immediately after the emergency conditions have passed.

Voltage control

180. (1) The system operator is responsible for the voltage control of the transmission system, at transmission level voltages as well as at the interface between the transmission company and its customers.

(2) Electricity must be supplied at three phase alternating current which must have a nominal voltage between phases and range, at the points of supply, as agreed between the participants.

(3) Transmission system voltages must be controlled during normal operation to be at least within statutory limits at the points of supply.

Fault reporting and analysis or incident investigation

181. (1) Generators must report loss of output and tripping of units and governing to the system operator within 15 minutes of the event occurring.

(2) Distributors and end-use customers must -

(a) report the loss of major loads (>5MVA) to the system operator within 15 minutes of the event occurring; and

(b) give warning of the reconnection of the loads referred to in paragraph (a) with at least 15 minutes advance notice.

(3) Incidents on the interconnected power system involving sabotage or suspected sabotage, as well as threats of sabotage must be reported to the system operator.

(4) Interruptions of supply, disconnections, under or over voltage incidents, quality of supply contraventions or any incident that materially affected the quality of the service to another participant must be formally investigated.

(5) A preliminary incident report must be available after three working days and a final report within three months.

(6) The system operator must -

(a) initiate the investigation contemplated in subcode (4);

(b) arrange for the writing of the report; and

(c) involve all affected participants.

(7) The participants referred to in subcode (6)(c) must make all relevant required

information available to the system operator.

- (8) a major incident must have the following additional requirements:
 - (a) any participant must have a right to request an independent audit of the report, at their own cost, if they are not satisfied with it; and
 - (b) recommendations must be implemented by the participants within the time frames specified.
- (9) incidents must also be reported to the Board as defined in the licence conditions.
- (10) system operator is responsible for developing and maintaining an adequate system of fault statistics.

Commissioning

182. (1) The system operator must verify commissioning or maintenance programmes concerning operating at major substations as far as is needed to ensure adequate co-ordination and reliability of the interconnected power system.

(2) All aspects of commissioning, by customers, of new equipment associated with the transmission connection, or re-commissioning of such existing equipment, must be agreed with the system operator in writing before such commissioning starts.

(3) The aspects referred to in subcode (2) include, but are 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.

(4) A minimum notice period of one month applies from the date of receipt of the request for all commissioning or re-commissioning.

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

(6) The transmission company and customers must perform all commissioning tests required in order to confirm that the transmission company and the plant and equipment of customers meets all the requirements of the Transmission Grid Code before going on-line.

(7) Where commissioning is likely to involve a requirement for dispatch or operating for test purposes, the customer must, as soon as possible, notify the system operator of the requirement including reasonable details as to the duration and type of testing required.

Risk of trip

- 183.** (1) Generators must identify and report all tripping risks to the system operator.

- (2) Participants must minimise the risk of tripping or loss of output on their own plant and equipment, associated with their operation and maintenance.
- (3) Special care must be taken by participants when planning or executing work on protection panels.
- (4) The normal outage process set out in code 184 must be followed.
- (5) The work referred to in subcode (3) must be treated as risk-related outages by the system operator.
- (6) When a risk of trip of equipment or loss of output with an impact exceeding 5MW could occur on any part of the interconnected power system, owing to an operation or maintenance contemplated in subcode (2) and (3), the affected participants must be consulted as to who must accept the risk before work may commence.
- (7) The system operator must always be informed of the operations and maintenance contemplated in subcode (2) and must in general coordinate the information and accept the risks.
- (8) The affected participants must be informed when the risk has been removed.

PART 2

MAINTENANCE COORDINATION OR OUTAGE PLANNING AND TELE-CONTROL

Maintenance coordination or outage planning

184. (1) Optimal reliability of the interconnected power system must be achieved by co-ordinating scheduled outages of generation, the transmission company, distributor, end-use customer, metering, communication and control facilities affecting interconnected power system operation.

(2) The maintenance coordination or outage planning must be done in collaboration with the single buyer.

Roles and responsibilities of outage requester

185. (1) An outage requester must be a formally nominated employee or agent of a distributor, generator, end-use customer or a transmission company.

- (2) The responsibilities of an outage requester are to request an outage on plant -
 - (a) for planned maintenance, repairs, auditing, emergency repairs, construction, refurbishment, inspection, testing; or
 - (b) to provide safety clearance for other activities such as servitude clearance, line crossings and underpasses.

Roles and responsibilities of transmission company outage scheduler

186. (1) The transmission company outage scheduler must check for multiple requests for an outage of the same network unit.

- (2) If the transmission company outage scheduler notices -

- (a) another outage request for the same bay, the transmission company outage scheduler must request the parties involved to combine their requests into a single outage; or
 - (b) conflicting outages, the transmission company outage scheduler must consider the priority and relative urgency of the requests and reflect the consideration against the validated request.
- (3) The transmission company outage scheduler is responsible for ensuring that negotiations of risk-related outages have taken place.

Roles and responsibilities of system operator outage scheduler

187. (1) The system operator outage scheduler is appointed to assess the viability of a scheduled outage request and to confirm or turn down the request.

(2) The system operator outage scheduler must optimise plant utilisation by evaluating network load capabilities, different system configurations and risk factors.

(3) It is also the responsibility of the system operator outage scheduler to co-ordinate and schedule plant that affects international customers.

Outage process

188. (1) The system operator controller on shift at the time of the outage is responsible for finally sanctioning or alternatively refusing the outage and ensuring that the relevant operating instructions are issued.

(2) The system operator must develop and maintain an electronic transmission maintenance scheduling system for the coordination of all transmission system outages.

(3) The transmission company must inform all customers of the name and contact details of the respective the transmission company outage schedulers in the different geographic parts of the country.

(4) The system operator must make available to customers an outage schedule of all planned outages on the transmission system.

(5) The outage schedule referred to in subcode (4) must cover a period of one year rolling and must indicate whether the status of the outage is confirmed or not.

(6) When the need for an outage is first identified and -

(a) the outage requester has access to the transmission maintenance scheduling system, the outage requester must enter the outage into the transmission maintenance scheduling system referred to in subcode (2) as a requested outage with planned outage dates, times, reason, type of maintenance and request urgency assigned to it; or

(b) the outage requester does not have access to the transmission maintenance scheduling system, the outage requester must contact the relevant transmission company outage scheduler or the system operator outage scheduler to enter the outage as contemplated in paragraph (a).

(7) When the transmission company outage scheduler is satisfied with the request

referred to in subcode (6)(b) and, in the case of a calculated risk, has ensured that negotiation has taken place with the relevant stakeholders the scheduler must mark the outage as a scheduled outage.

(8) When the outage is marked as contemplated in subcode (7), the system operator outage scheduler must confirm the scheduled outage if the scheduled outage satisfies all the necessary requirements.

(9) If the scheduled outage is confirmed as contemplated in subcode (8) the transmission company outage scheduler must change the request referred to in subcode (6)(b) to a confirmed booking in the transmission maintenance scheduling system referred to in subcode (2).

(10) If the confirmed booking referred to in subcode (9) is subject to the outcome of another booking, the confirmed booking under subcode (9) must reflect that it is linked to another booking.

(11) If the request referred to in subcode (6)(b) cannot be accommodated, it must be marked as refused, with a reason or an alternative suggestion, in the transmission maintenance scheduling system referred to in subcode (2).

(12) When it is time for the confirmed booking referred to in subcode (9) to be executed or the outage becomes effective, the status must be changed or taken by the system operator controller who is on shift if sanctioning the outage.

(13) While an outage is in progress the responsible participants may report the actual state of the progress to the system operator controller who is on shift, who must enter the actual state into the transmission maintenance scheduling system referred to in subcode (2) so that the progress of the outage may be monitored by the outage requester and other participants who may be affected by the requested outage.

(14) When the outage is completed and power is restored, the system operator shift controller must change the status of the outage to complete.

(15) When an outage is cancelled it is the responsibility of the person cancelling the outage to furnish the reasons for the cancellation to the system operator.

(16) The system receiving the cancellation contemplated in subcode (15) must enter the cancellation into the transmission maintenance scheduling system referred to in subcode (2) and change the status to cancelled.

(17) Subcodes (15) and (16) also apply to outages that are postponed.

Risk-related outages

189. (1) All risk-related outages must be scheduled a minimum of 14 days in advance with an executable contingency plan in place.

(2) The compilation of the contingency plan referred to in subcode (1) is the responsibility of the relevant transmission company.

(3) The contingency plan referred to in subcode (1) -

(a) is, in some cases, of a permanent nature and in force every time the same system conditions occur; and

(b) may only be prepared once and comes into force again, with minimal changes if needed, when the same outage is scheduled.

- (4) The contingency plan referred to in subcode (1) consists of the following five parts:
 - (a) security linking prior to the outage, to ensure minimal risk to customers;
 - (b) returning the plant that is on outage back to service as soon as possible;
 - (c) restoring supply to customers by utilising by-pass schemes;
 - (d) load shedding if necessary and load profiles must be made available by the customer; and
 - (e) list of contact persons.
- (2) -
 - (5) When a transmission company compiles a contingency plan pursuant to subcode
 - (a) the system operator is responsible for identifying risk-related outages;
 - (b) the system operator and customer control centres are responsible for the security linking contemplated in subcode (4)(a);
 - (c) the transmission company is responsible for supplying the information relating to returning the plant to service;
 - (d) the transmission company must develop by-pass schemes with assistance from the system operator and the customer control centre; and
 - (e) the system operator and customer control centres are responsible for identifying the load at risk and load shedding in the contingency plan.
 - (6) If the contingency plan referred to in subcode (1) indicates that load shedding must take place, the contingency plan must include -
 - (a) the total amount of load to be shed in relation to the load profile; and
 - (b) the point at which load of customers must be shed for optimal results.
 - (7) The customer control centre must confirm that it is possible to execute the contingency plan successfully.
 - (8) The outage scheduler must contact the control centre a day prior to the outage to ensure that the control centre is in possession and aware of the contingency plan.
 - (9) Negotiation of all risk-related outages must take place with affected customers a minimum of 14 days prior to the outage being executed unless otherwise agreed.
 - (10) Where a request for a risk related outage comes from a generator with a requirement for 28 days prior notice of the risk related outage, the time period must be complied with by the parties.
 - (11) The service provider must involve customers in the planning phase of projects and

outages that will affect them.

(12) Subcodes (1) to (11) apply also to all outages affecting international customers.

(13) The transmission company must give distributors and end-use customers at least 14 days prior notice of planned interruptions.

Maintenance planning between transmission company and generators

190. (1) Each generator must provide the system operator with the following documents in the pro-forma format set out in Annexure 10 to enable the system operator to execute short-term power system reliability inclusive of -

- (a) a 52-weeks-ahead outage plan per power station, showing planned outage and return dates and other known generation constraints, updated weekly by 15:00 every Monday or the first working day of the week;
- (b) an annual maintenance or outage plan per power station, looking five years ahead, showing planned outage and return dates and other known generation constraints, and issued by 31 December of each year; or
- (c) a monthly variance report, explaining the differences between the plan contemplated in paragraph (a) or (b).

(2) Each generator must invite the transmission company to provide inputs into the compiling of the annual maintenance or outage plan referred to in subcode (1)(b), on the basis of ensuring system reliability, and must not unreasonably reject the inputs.

(3) If a generator rejects the inputs contemplated in subcode (2) the generator must substantiate the rejection as reasonable by providing the transmission company with documentary proof of the reasons for the rejection.

(4) Plant versus system risks must be carefully weighed up by the affected participants under all circumstances.

(5) Joint risk assessments must be undertaken and joint contingency plans under these outage conditions must be prepared by the affected participants.

(6) Each generator must ensure the absolute minimum deviation from its annual outage plan and each deviation must be negotiated with the system operator.

(7) The system operator must coordinate network outages affecting unit output with related unit outages to the maximum possible extent.

(8) The objectives to be used by the system operator in this maintenance coordination -

- (a) maintaining adequate reserve levels at all times;
- (b) ensuring reliability where transmission system constraints exist; and
- (c) maintaining acceptable and consistent real-time technical risk levels.

Refusal or cancellation of outages

191. (1) A participant may not unreasonably refuse or cancel a confirmed outage.

(2) If a participant unreasonably refuses or cancels a confirmed outage the participant is liable for the risks associated with that refusal or cancellation.

(3) In the case of the system operator cancelling the request owing to system conditions, the outage requester must bear the cost of such cancellation.

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

192. (1) The system operator must -

(a) determine system conditions; and

(b) communicate the system conditions determined under paragraph (a) to all participants.

(2) The system conditions contemplated in subcode (1)(a) are -

(a) based on a steady state and dynamic simulation of the interconnected power system; and

(b) include measures that will enhance reliability.

(3) The system operator must provide participants with operational information as may be agreed from time-to-time and as contemplated in Part 2 of Chapter 6.

(4) The operational information under subcode (3) includes information regarding planned and forced outages on the interconnected power system as determined by the market rules.

(5) The system operator must report on both technical and energy aspects of interconnected power system performance monthly and annually.

(6) The reporting pursuant to subcode (5) includes information on daily demands, energies, losses, interruptions and Codes 229, 230, 231 and 232.

(7) The system operator must, on request by a participant, make available the information contemplated in subcode (6).

Tele-control

193. Where tele-control facilities are shared between participants, operating procedures must be agreed.

CHAPTER 5 TRANSMISSION SYSTEM METERING

Principles of transmission metering

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

(a) each point of supply connecting a distributor or end-use customer to the transmission system;

(b) each point of connection between a unit and a distributor or the transmission system; and

(c) each point connecting the networks 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 057:2001 metering specifications.

(3) Customers with a maximum demand of 5 MVA or more, generators and connections to neighbouring countries must have main and check metering and there must be separate main and check Current Transformer cores but one dedicated Voltage Transformer 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 party and the transmission metering administrator must install and control the check meters.

Responsibility for metering installations

195. (1) For the purposes of this Chapter, the transmission company is the transmission metering administrator and owner of the meter.

(2) The transmission supply business is responsible for ensuring that all points identified as metering points under code 202 have metering installations.

(3) The transmission metering administrator is responsible for managing and collecting metering information.

(4) Participants connected to or wanting to connect to the transmission system must provide the transmission metering administrator with all information considered necessary to enable the transmission metering administrator to perform metering duties.

(5) 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 Chapter;

(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

196. (1) The following principles apply to all metering installations:

(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 access is restricted to authorised staff members only; Data for customers must be historical data situated on a secure server. As and when required, metering impulses must be provided;
- (e) a telecommunications medium must be connected to the meter or recorder contemplated in paragraph (a) where possible; and
- (f) the meter data retrieval process must be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories.
- (g) The accuracy of meters and recorders must be in accordance with the minimum requirements of NRS 057:2001 metering specifications.
- (h) Commissioning of the metering installation and metering data supporting systems must take place in accordance with the requirements of NRS 057:2001 metering specifications.
- (i) Both active and reactive energy must be measurable without compromising any requirements of this Chapter.
- (j) The meters must measure both active and reactive energy flow in both directions.
- (k) The meters must be configured to store or record metering data in half-hourly integration periods.
- (2) 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 Voltage Transformer or Current Transformer circuitry.
- (3) Metering installations must be audited in accordance with NRS 057:2001 metering specifications or equivalent.

Data validation

197. (1) Data validation must be carried out in accordance with NRS 057:2001 metering specifications.

- (2) In the event of -
 - (a) electronic access to the meters not being possible;
 - (b) an emergency bypass or other scheme having no metering system; or
 - (c) metering data not being available any of the following may be resorted to by the distributor,

the transmission metering administrator 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 transmission metering administrator 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 transmission metering administrator must ensure that the meters are downloaded for the billing cycle.

Meter verification

198. In addition to the NRS 057:2001 metering specifications verification requirements, meter readings must be compared with the metering data base at least once a year.

Metering database

199. (1) The transmission metering administrator 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 4.2 of the NRS 057:2001 metering specifications must form part of the metering database and must be retained for at least five years for audit trail purposes.

Testing of metering installations

200. (1) Commissioning, auditing and testing of metering installations must be done in accordance with the NRS 057:2001 metering specifications.

(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 transmission metering administrator if the meter is found to be inaccurate.

Metering data base inconsistencies

201. In the event of testing revealing that data in the metering database is inconsistent with the data in the meter, the transmission metering administrator must inform all affected participants and make corrections to the official metering data.

Access to metering data

202. (1) Metering data must be accessed through a central database that stores all customer information.

(2) The transmission metering administrator 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 transmission metering administrator in line with section 4.2.3 of the NRS 057:2001 metering specifications.

(5) All security requirements for metering data must be as specified in NRS 057:2001 metering specifications.

Confidentiality

203. Metering data and passwords are confidential information.

CHAPTER 6 TRANSMISSION SYSTEM INFORMATION EXCHANGE

PART 1 INFORMATION EXCHANGE INTERFACE AND SYSTEM PLANNING INFORMATION

Confidentiality of information

204. (1) Information exchanged between parties governed by this Chapter is confidential unless otherwise stated or the information is defined as being in the public domain.

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

(3) Parties must observe the proprietary rights to information of third parties for the purposes of this Chapter.

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

(5) The information owner may request the receiver of information to enter into a confidentiality agreement with the information owner before the information owner provides confidential information.

(6) A pro forma confidentiality agreement is set out in Annexure 7.

(7) Parties must -

(a) take all reasonable measures to control unauthorised access to information and to ensure secure information exchange; and

(b) must report any violation of information security to the information owner.

Information exchange interface

205. (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 confirmation procedures for the transfer of information.

(3) Access to information must be provided by the relevant parties with reasonable motivation and notice.

System planning information

206. (1) Customers must -

(a) provide to the transmission company, without unreasonable delay, information requested by the transmission company on a regular basis for purposes of -

(i) planning and developing the transmission system;

(ii) monitoring current and future power system adequacy and performance; or

(iii) fulfilling statutory or regulatory obligations; and

(b) submit to the transmission company the information listed in Annexure 15 and -

(i) Annexure 8, for distributors or end-use customers; or

(ii) Annexure 9, for generators.

(2) The transmission company must keep an updated technical database of the

interconnected power system for purposes of modelling and studying the behaviour of the interconnected power system.

(3) The transmission company must provide customers or potential customers, upon request, with any relevant information that they require to properly plan and design their own networks or installations or comply with their other obligations in terms of the Transmission Grid Code.

(4) The transmission company must make available all the relevant information related to network planning as contemplated in Part 3 of Chapter 3.

(5) Customers must, upon request to upgrade an existing connection or when applying for a new connection, provide the transmission company with information relating to the details specified in Annexure 16.

(6) The service-provider may estimate any system planning information not provided by the customer as contemplated in Annexure 8 or 9.

(7) The service-provider must indicate to the customer any data items that have been estimated and the estimated data items are deemed to have been provided by the customer.

(8) Generators must submit to the relevant service-provider all the information set out in Annexure 10 with regard to each generating unit at each power station.

PART 2 OPERATIONAL INFORMATION

Pre-commissioning studies

207. (1) Customers must meet all system planning information requirements before the commissioning test date.

- (2) The system planning information requirements under subcode (1) include -
 - (a) confirming any estimated values assumed for planning purposes; or
 - (b) where practical, replacing the estimated values contemplated in paragraph (a) with validated actual values and with updated estimates for the future.
- (3) The system operator must perform pre-commissioning studies prior to -
 - (a) sanctioning the final connection of new or modified plant to the transmission system; and
 - (b) using data for exciter, turbine governor, High Voltage Direct Current systems, Flexible Alternating Current Transmission Systems device parameters and settings supplied by customers,

to verify that all control systems are correctly tuned and planning criteria have been satisfied.

(4) The system operator may request adjustments prior to commissioning should tuning adjustments be found to be necessary by the system operator.

(5) Participants must ensure that exciter, turbine governor, Flexible Alternating Current Transmission Systems and High Voltage Direct Current control system settings are as finally recorded by the system operator prior to commissioning.

Commissioning and notification

208. (1) Participants must give the system operator reasonable advance notice referred to in code 182, of the time at which the commissioning tests will be carried out.

(2) The system operator and the participant must agree on the timeous provision of operational data items set out in Annexure 11.

(3) Participants must jointly verify all measurements and indications for functionality and accuracy once every three years so as to achieve overall accuracy of operational measurements within the limits agreed.

(4) Records of commissioning must be -

(a) maintained for reference by the system operator for the operational life of the plant; and

(b) made available, within a reasonable time, to authorised participants upon request.

(5) A customer connected to the transmission system must ensure that measurement equipment complies with the accuracy classes set out in Annexure 17.

General information acquisition requirements

209. (1) Customers and the transmission company must supply measurements and indications, including the standards set out in Annexure 11, to the system operator.

(2) Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the information supplied in terms of subcode (1) the provider of the information must report and restore or correct the signals and indications as soon as reasonable.

(3) The measurements and indications contemplated in subcode (1) must be presented to the system operator in a form nominated by the system operator.

(4) The system operator must give notice to a participant if the system operator determines that additional measurements or indications in relation to a plant or equipment of the participant are needed to meet a transmission system requirement.

(5) The costs related to a modification to the transmission system are for the account of the provider of information referred to in subcode (2).

(6) On receipt of the notice contemplated in subcode (4) a participant must promptly ensure that the measurements or indications are made available at the remote terminal unit.

(7) The data formats to be used and the fields of information to be supplied to the system operator by the various participants are set out in Annexure 11.

Generating unit scheduling

210. The single buyer must provide the data set out in Annexure 12 to the system operator.

Energy market schedules

211. (1) The single buyer must provide the system operator with the daily 24 hours day-ahead energy schedule and the daily price curve before 16:00 Central African Time each day.

(2) After 16:00 Central African Time, the energy schedule referred to in subcode (1) must be made available hourly to ensure the transfer of a new schedule owing to a reschedule by the system operator.

(3) The system operator must import the energy schedule referred to in subcode (1) hourly, at five minutes to the hour, for dispatch.

Ancillary services market schedules

212. (1) The single buyer must provide the system operator with the daily 24 hours day-ahead ancillary service market schedule before 16:00 Central African Time each day.

(2) After 16:00 Central African Time, the ancillary service market schedule referred to in subcode (1) must be made available hourly to ensure the transfer of a new schedule owing to a reschedule by the system operator.

(3) The system operator must import the ancillary service schedule hourly, at five minutes to the hour, for dispatch.

(4) All information exchange requirements for ancillary services that are contracted annually must be included in the contract between the parties.

File transfers

213. (1) The format of the file used for data transfer through file transfers must be negotiated with the system operator.

(2) The data must be made available in a common electronically protected directory.

(3) All file transfer data must be collected by the system operator in line with the file format set out in Annexure 18.

Inter control centre communication

214. (1) All customer control centres must provide the system operator with network information that is considered reasonable for the security and integrity of the transmission system on request.

(2) The system operator must communicate network information as requested to the customer control centres, as required for safe and reliable operation.

(3) The information exchange between control centres must be electronic and paper-based within the time-frame agreed upon.

Communication facilities requirements

215. The minimum communication facilities for voice and data that are to be installed and maintained between the system operator and participants must -

(a) comply with the applicable International Electro-technical Commission standards for Supervisory Control and Data Acquisition and communications equipment; and

(b) meet the standards set by the system operator in advance of the design of communication facilities..

Information Exchange Tele control

216. (1) The information exchange must support data acquisition from remote terminal units.

(2) The system operator must be able to monitor the state of the interconnected power system via telemetry from the remote terminal unit connected to the plant of a participant.

(3) The signals and indications required by the system operator are set out in Annexure 9, together with other information the system operator may from time to time reasonably require by notice to the participant.

(4) Participants must interface via the standard digital interfaces, as specified by the system operator.

(5) Interface cabinets must be installed in the plant and equipment room of a participant if required by the system operator.

(6) A participant is responsible for providing and maintaining the signalling from the plant and equipment of the participant to the interface cable.

(7) A participant must provide the capability -

(a) for the system operator to deactivate and reactivate the scanning of a given remote terminal unit; and

(b) of monitoring the availability of all remote terminal units centrally.

(8) A participant must comply with the tele control requirements -

(a) applicable to the primary control centre; and

(b) reasonably required for the emergency control centre,

of the system operator.

Telephone or facsimile

217. (1) A customer is responsible for the provision and maintenance of no less than one telephone and one facsimile unit that must be reserved for operational purposes only, and must be continuously attended to and answered without undue delay.

(2) The system operator must use a voice recorder for historical recording of all operational voice communication with participants.

(3) The voice recordings contemplated in subcode (2) must be available for at least three months.

(4) The system operator must make the voice records of an identified incident in dispute available within a reasonable time period upon request by a participant or the Board.

Electronic mail

218. (1) Participants must provide the system operator with the electronic mailing address of the contact person and the system operator must provide participants with the mailing address of the contact person of the system operator.

(2) The service-provider must be selected to meet the real-time operational requirements of the system operator.

Access and security of infrastructure at points of supply

219. (1) The system operator must agree with participants on the procedures governing security and access to the Supervisory Control and Data Acquisition (SCADA), computer and communications equipment of the participants.

(2) The procedures under subcode (1) must allow for adequate access to the equipment and information by the system operator for purposes of maintenance, repair, testing and the taking of readings.

(3) A participant must -

(a) designate a person to perform the duties of the information owner in respect of the granting of access to information to third parties; and

(b) disclose the name and contact details of the person designated pursuant to paragraph (a) to the Board.

(4) A participant may, pursuant to subcode (3)(a), designate more than one person.

Time standards for infrastructure at points of supply

220. (1) All information exchange must be global positioning system satellite time signal referenced.

(2) The system operator must ensure broadcasting of the standard time to relevant telecommunications devices in order to maintain time coherence.

Integrity of installation

221. (1) A participant is responsible for optimising the reliability and security of the facilities to comply with the system operator equipment and Original Equipment Manufacturer minimum requirements.

(2) The optimising of reliability and security contemplated in subcode (1) includes the provision, at no charge to the system operator, of an uninterruptible power supply with an eight-hour standby capacity.

Data storage and archiving

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

(2) A party -

(a) must have a system for storing data and information to be used by the party; and

(b) is responsible for own choice, and the costs, of the system contemplated in paragraph

- (a).
- (3) A system contemplated in subcode 2 must -
- (a) be auditable by a party authorised to audit the system;
- (b) provide for clear and accessible audit trails on all relevant operational transactions.
- (4) All requests that require an audit on a system contemplated in subcode 2 must be undertaken with reasonable notice to the parties.
- (5) The information owner must keep all information for a period of at least five years from the date the information was created, unless otherwise specified in the Transmission Grid Code.
- (6) The parties must ensure reasonable security against unauthorised access, use and loss of information of the systems that contain the information.

PART 3 POST-DISPATCH INFORMATION

Market information

223. (1) The system operator and the transmission metering administrator must provide participants, including the single buyer, with the information contemplated in codes 210, 211 and 212.

(2) Before the finalisation of the information referred to in subcode (1) the information must be provided in accordance with codes 224 to 227.

Generation settlement

224. (1) The single buyer must request all data required for settlement of the energy market from the transmission company.

(2) On a request pursuant to subcode (1), the transmission company must make the data available to the single buyer within an agreed time period and acknowledge that the data is confidential.

Ancillary services settlement

225. (1) The single buyer must request all data required for settlement of the ancillary services market from the transmission company.

(2) The transmission company must make this information available, within an agreed time period, with acknowledgement of the confidentiality of the data requested.

Additional generating unit post-dispatch information

226. The system operator must provide operational information regarding generating unit dispatch and overall dispatch performance as specified in Annexure 13.

Hourly demand metering data

227. The transmission metering administrator must provide participants with hourly metered data pertaining to their installations.

Files used for data transfer

228. (1) The format of the files used for data transfer must be negotiated and defined by the supplier and receiver of the information.

(2) The file transfer media must be negotiated and defined by both parties involved.

(3) The parties must keep the agreed number of files for backup purposes so as to enable the recovery of information in the case of communication failures.

(4) The files that may be triggered in the transmission system and the frequency of the occurrence of the events that trigger the files are set out and described in Annexure 19.

Generator performance data

229. Generators must provide the system operator monthly with official performance indicators in relation to each generating unit at each power station in respect of availability or reliability as detailed in Annexure 14.

Distributor and end-use customer performance

230. (1) The performance measurement of all distributors and end-use customers must be in accordance with the quality-of-supply requirements as contemplated in code 71(2)(b)

(2) Periodic testing of under-frequency load shedding relays must be reported in the format set out in Annexure 20.

System performance information

231. (1) The transmission company must make available monthly the performance indicators for the transmission system, in the format set out in Annexure 21, to the Board, customers and the single buyer.

(2) The transmission company must contract point of supply performance with each customer.

(3) The point of supply performance under subcode (2) includes performance reporting requirements.

System performance information

232. (1) The following interconnected power system operational information must be made available by system operator -

(a) daily:

(i) the hourly actual demands of the previous day (MW); and

(ii) the reserve amounts over the morning and evening peaks of the previous day

(MW); and

- (b) annually:
 - (i) the annual peak (MW), date and hour; and
 - (ii) the annual minimum MW, date and hour.

CHAPTER 7 TRANSMISSION SYSTEM RENEWABLE ENERGY TECHNOLOGIES

Frequency response

233. (1) During network frequency deviations a connected renewable energy plant or PV plant must have the following frequency response settings as depicted in Annexure 22:

- (a) a dead band setting or constant power versus frequency response in a band settable around the nominal frequency of 50Hz with a resolution of 0.05Hz ($49\text{Hz} \leq f_1 < 50\text{Hz} < f_2 \leq 51\text{Hz}$);
- (b) an upper band frequency setting where $f_2 < f < f_3 < 52.5\text{Hz}$ the power is ramped down at a settable rate to a % of active power order in accordance with a droop setting of $k_2 = dP/df < 0$;
- (c) power is ramped down to 0 for $f > f_3 < 52.5\text{Hz}$ with the option to disconnect from the grid;
- (d) if the over-frequency does not exceed f_3 and power has been ramped down, and the frequency decreases again towards the upper dead band frequency f_2 , it is only ramped up again to a percentage of the power before the disturbance.
- (e) the power after disturbance (P_{ad}) is equal to the power before the disturbance (P_{bd}) which is normally also equal to the maximum available power times a factor k_3 , thus $k_3 = P_{ad}/P_{bd} < 1$;
- (f) a lower band frequency setting where $48\text{Hz} < f_0 < f < f_1$ power is ramped up to a % of max available power at that time, if more power is available than before the disturbance or if an inherent overload capability exists, in accordance with a droop setting of $k_1 = dP/df < 0$;
- (g) for frequencies below f_0 , power remains constant with the option to disconnect from the grid for frequencies lower than 48Hz;
- (h) once power is ramped up for $f_0 < f < f_1$, it can be ramped down again when $f_1 < f < f_2$ automatically to normal power setting as it was set during pre-transient operation; or
- (i) after a disturbance where the k_3 factor has come into play, a reset command should be available to restore the power order to the maximum available power order with an optional automatic reset after settable time duration.

Voltage operating and regulation requirements

- 234.** (1) A connected renewable energy plant must be able to -
- (a) operate continuously at a voltage range of 0.9pu – 1.1pu at frequencies of 49Hz to 51Hz for -

- (i) conditions outside the transient response required for low voltage ride-through set out in code 235; and
 - (ii) the transient frequency response required in code 233;
 - (b) trip after 2 seconds of steady-state over- and under voltage;
 - (c) trip after 3 seconds of steady-state over or under frequency; and
 - (d) regulate the voltage within its reactive power capabilities at a voltage set point settable between 0.9pu and 1.1pu voltage and the voltage set point should be settable with a resolution of 0.01pu or smaller.
- (2) A steady-state voltage ramp rate must be settable in a range of 1kV/min to 100kV/min.
- (3) Transient voltage control loop gain settings should be adjustable as recommended by dynamic studies performed for each project or network location of the plant.
- (4) Switching in or out of feeders or equipment inside the plant must not cause a transient voltage change of more than 0.02pu voltage at the point of common coupling for normal fault level conditions, and not more than 0.05pu under pre-defined network contingencies or minimum fault level.
- (5) Transient overvoltage conditions to be catered for are to be in accordance with relevant IEC equipment standards.

Low voltage ride-through requirements

235. (1) During a voltage dip, a connected renewable energy plant must have the low voltage ride-through ability to -

- (a) stay connected to the network; and
- (b) give full available capacitive reactive power support for events where the voltage of the lowest phase is -
 - (i) $0 \text{ pu} < U < 1 \text{ pu}$ for $t \leq 0.2\text{s}$;
 - (ii) $U > 0.47222t - 0.09444 \text{ pu}$ for $0.2 < t \leq 2\text{s}$; or
 - (iii) $U > 0.85$ for $2 < t \leq 120\text{s}$.

(2) For transient voltages, with the plant availing maximum reactive power or as required, below the nominal voltages and with longer durations than given in subcode (1)(b), the renewable energy plant may disconnect and reconnect to the network within 1 second after the voltage has recovered to $>0.9\text{pu}$ of nominal voltage.

(3) An illustrative clarification of low voltage ride-through response contemplated in subcodes (1) and (2) is set out in Annexure 23.

Reactive power control

236. (1) A renewable energy plant must not require any reactive power to start up if the voltage is within the 0.9pu to 1.1pu range.

(2) Both power factor control and voltage control with voltage set point capability as specified in code 234 must be available for all plants.

(3) Power factor must be settable at 0.9 lagging to 0.9 leading in power factor control mode at maximum rated power, and reactive power equal to the power factor control mode reactive power capability at maximum power must be available for voltage support in voltage control mode at any power order as shown in the PQ Capability Chart in Annexure 24.

(4) Constant Q control mode is deemed optional.

(5) Where Q control is provided, the steady-state ramp rate (MVAR/min) and resolution should be similar to equate to the voltage regulation requirements for the specific network lowest fault level case.

Active power control

237. (1) Any connected renewable energy plant must be able to reduce active power below the immediate available power level of a plant.

(2) Any change of active power level must be governed by a power ramp rate (MW/min) agreed between the generation plant and the transmission company or system operator and be settable between 1% of plant power rating/min and 50MW/min.

(3) The ramp rate must be settable for different operations such as start-up, shut-down, and normal power order changes.

(4) The active power must not be influenced by the voltage at point of common coupling given that it is within the range as set out in code 234.

Harmonic distortion requirements

238. (1) Total voltage harmonic distortion and individual voltage harmonics caused by the connected renewable energy plant must not exceed the levels given in Annexure 25, but the system operator may limit the total voltage harmonic distortion and individual voltage harmonics below the levels given in that Annexure.

(2) Current harmonics may not be specified for generating plant except where the transmission company or system operator can motivate certain limitations for exceptional cases due to possible normal-based or contingency-based harmonic resonance conditions or harmonic cross-modulation with other network devices.

(3) The IEEE-519-1992 standard may serve as a general guideline to harmonic distortion requirements.

Unbalance requirements

239. The fundamental negative phase sequence voltage component generated by the connected renewable energy plant must not exceed 2% compared to the fundamental positive phase sequence voltage component.

General protection and control requirements

240. The following protection and control functionality must be available for each renewable energy plant interface with the transmission or distribution grid:

- (a) islanding detection and settable response for island frequency control or shutdown;
- (b) dead network start-up blocking;
- (c) synchronising facilities with network;
- (d) configurable inter-trip and runback signals;
- (e) protection functions such as definite- and inverse definite minimum time (IDMT) over-current, earth fault detection, differential protection, overvoltage detection, as agreed between the parties;
- (f) unitised protection for transformers, cables, and busbars;
- (g) where protection or control signals are exchanged, interface point details including -
 - (i) wetting voltage;
 - (ii) junction box terminal layout;
 - (iii) cable numbering or fibre optic patch panel,will be as agreed between the parties;
- (h) other requirements that the transmission company or network operator considers necessary; and
- (i) metering requirements are as set out in Chapter 5.

General telecommunication and Supervisory Control and Data Acquisition (SCADA) requirements

241. (1) Telecommunications interface between the plant and the transmission company network via fibre optic or power line carrier must be available as agreed between the transmission company and the renewable energy plant.

(2) Supervisory Control and Data Acquisition protocol capability to the national control centre is available either via IEC60870-5-101, IEC60870-5-104 or IEC61850.

(3) The Supervisory Control and Data Acquisition signals to be made available, by the renewable energy plant, for network operations, to the national control centre are -

- (a) relevant indications such as breakers, disconnectors, and earth links;
- (b) alarm indications including plant protection alarms or auxiliary alarms;
- (c) analogue values including active power, available active power, reactive power, voltage, current, frequency, tap changer positions, active set points, wind information or solar information;
- (d) control of analogue set points including active power set point, voltage set point or power factor set point; and
- (e) control commands including start, stop or reset of maximum available power after

disturbance, relevant breaker open or close must be available as agreed.

(4) Supervisory Control and Data Acquisition protocol address lists, update rates or dead-bands for analogue and digital indications must be agreed during project execution.

Power system studies and models

242. (1) A renewable energy plant dynamic model must be -

(a) made available by the renewable energy plant to the transmission company, in the form of at least two software packages agreed on by the renewable energy and the transmission company, for network dynamic studies and protection studies; and

(b) structured to -

(i) be a detailed, topology, model describing the structure of the wind power plant.

(ii) be an aggregated model of the wind power plant, that describes the plant by means of one equivalent wind turbine generator and renewable energy plant component or a few equivalent wind turbine generator components and renewable energy plant components; and

(iii) enable at least the modification of the parameters of voltage control and reactive power control functions relating to the specifications of network parameters.

(2) The functionalities relating to active and reactive power control must be executable freely during a simulation run by means of a modifiable interface for power control.

(3) Renewable energy electromagnetic transient models or harmonic load flow models must be made available to the transmission company, in the form of at least two software packages agreed on by the renewable energy plant and the transmission company, for harmonic integration studies.

(4) If electromagnetic transient models referred to in subcode (3) are not available, harmonic current generation may be given as a percentage of fundamental current with phase rotations and relative angles specified.

(5) Reduced network models of the transmission or distribution network can be provided to a renewable energy plant manufacturer or photovoltaic plant manufacturer for internal protection studies or harmonic studies.

Energised system testing

243. (1) In order to verify the performance of a renewable energy plant energised system testing and measurements must be conducted in conjunction with the transmission company as agreed by the renewable energy plant and the transmission company.

(2) The energised system testing referred to in subcode (1) may include -

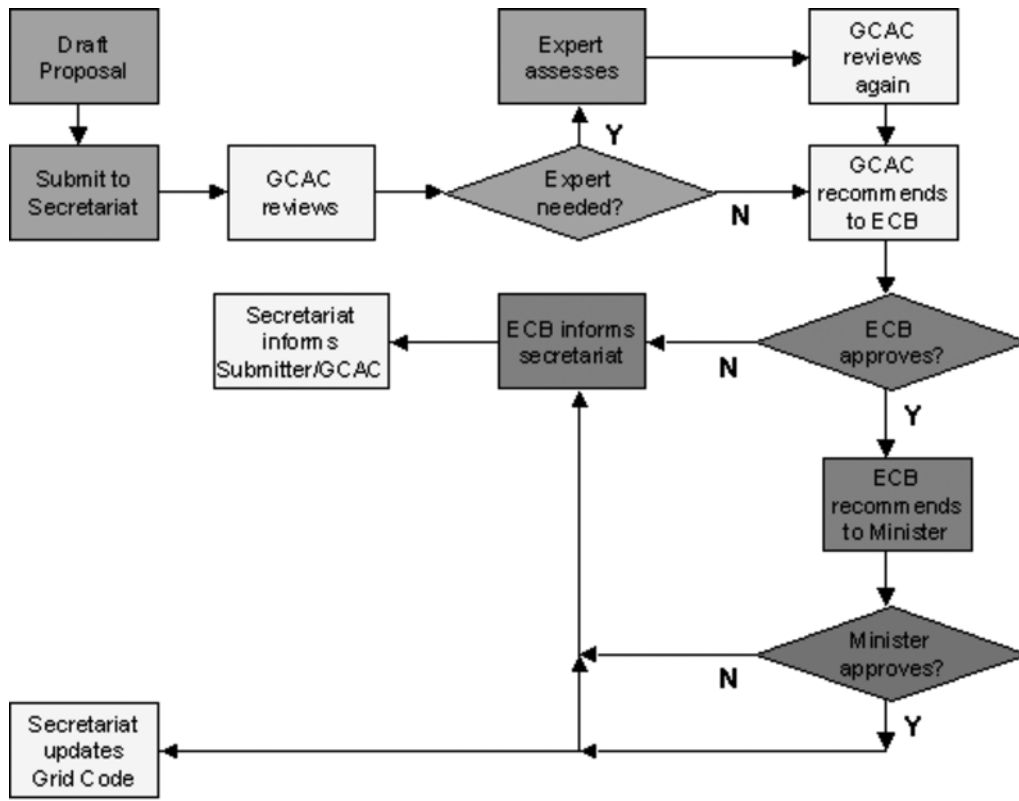
(a) auditing of metering systems and verification of plant maximum power output;

(b) control mode selection changes including V-control, PF-control or Q-control and step response tests as agreed by the parties;

- (c) power order set point tests, power ramp tests, voltage set point tests or voltage ramp tests, as agreed by the parties;
 - (d) verification of PQ capability curve as far as network configuration allows within allowable voltages;
 - (e) island detection test;
 - (f) staged single phase fault on transmission company side of point of common coupling to test low voltage ride-through response with transient recordings as agreed;
 - (g) harmonic voltage and current measurements at the point of common coupling for different power levels as agreed by the parties and during a one week continuous operation with different system configurations;
 - (h) other tests as agreed by the parties; or
 - (i) plant-side information and data recorded by dynamic system monitors, wind or solar measurements, harmonic content or voltage dip monitoring made available as contemplated in subcode (3).
- (3) Plant-side information and data recorded by dynamic system monitors, wind or solar measurements, harmonic content or voltage dip monitoring must be made available during and after energised system testing referred to in subcode (1) to compare with the transmission company side measurements for the purposes of performance verification, control system tuning and planning information.
- (4) On-line access to plant-side information with required security measures would be an advantage.

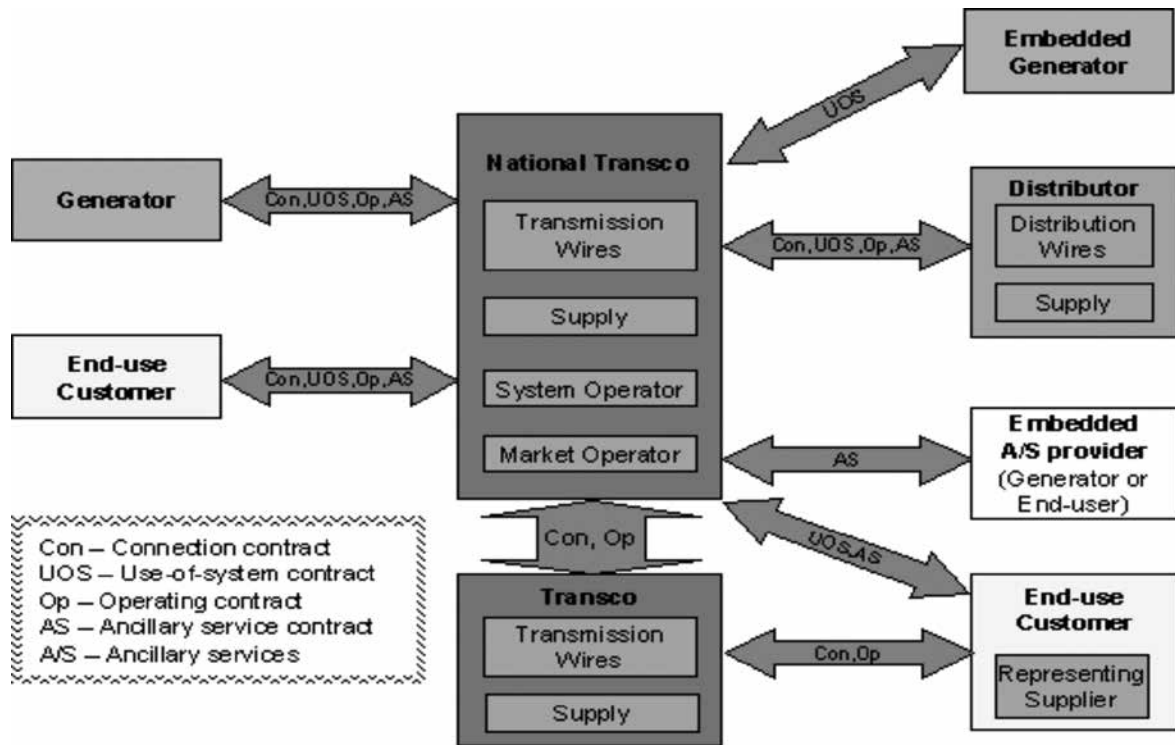
ANNEXURE 1

TRANSMISSION GRID CODE AMENDMENT OR EXEMPTION APPROVAL PROCESS



ANNEXURE 2

CONTRACTING FRAMEWORK FOR PARTICIPANTS



ANNEXURE 3

GENERATOR CONNECTION CONDITIONS

Table 1: Summary of the requirements applicable to specific classes of units							
Grid Code Requirement		Units other than Hydro (MVA rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR1	Plant availability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR3	Protection						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes
	- Loss of Field	-	Depends on System Requirements	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes
	- Trip to House Load	-	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes
	- Gen TRANSFORMER backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- HV Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- HV Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- Unit Switch-onto-standstill Protection		Depends on System Requirements	Yes	Yes	Yes	Yes
	- Main Protection only	Yes	Yes	Depends on System Requirements	-	-	-
	- Main Protection (monitored) or main and backup	-	-		Depends on System Requirements	-	-
	- Main and Backup Protection (both monitored)	-	-	-		Depends on System Requirements	Yes

GCR4	Ability To Island	-	-	Depends on System Requirements	Yes	Yes	Yes
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabilizer	-	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes
	- Limiters	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR7	Multiple <i>Unit</i> tripping	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 <i>unit</i> at station
GCR8	<i>Governing</i>	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 <i>unit</i> at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR11	External Supply Disturbance Withstand Capacity	Depends on System Requirements	If more than 5 <i>unit</i> at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 <i>unit</i> at station
GCR12	On load tap Changer for generating <i>Unit</i> step up transformers	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GRC13	<i>Emergency unit</i> capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR14	Independent action for control in system island	-	-	Depends on System Requirements	Yes	Yes	Yes

Table 2: Summary of the requirements applicable to specific classes of units							
Grid Code Requirement		Hydro Units (MVA rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR1	Plant availability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR3	Protection						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes
	- Loss of Field	-	Depends on System Requirements	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes
	- Trip to House Load	-	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes
	- Gen <i>TRANSFORMER</i> backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- <i>HV</i> Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- <i>HV</i> Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- <i>Unit</i> Switch-onto-standstill <i>Protection</i>		Depends on System Requirements	Yes	Yes	Yes	Yes
	- Main <i>Protection</i> only	Yes	Yes	Depends on System Requirements	-	-	-
	- Main <i>Protection</i> (monitored) or main and backup	-	-		Depends on System Requirements	-	-
	- Main and Backup <i>Protection</i> (both monitored)	-	-	-		Depends on System Requirements	Yes
GCR4	Ability To <i>Island</i>	-	-	-	-	-	-
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabilizer	-	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes

	- Limiters	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR7	Multiple <i>Unit</i> tripping	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 <i>unit</i> at station
GCR8	<i>Governing</i>	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 <i>unit</i> at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR11	External Supply Disturbance Withstand Capacity	Depends on System Requirements	If more than 5 <i>unit</i> at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 <i>unit</i> at station
GCR12	On load tap Changer for generating <i>Unit</i> step up transformers	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GRC13	<i>Emergency unit</i> capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR14	Independent action for control in system island	-	-	Depends on System Requirements	Yes	Yes	Yes

Table 3: Standard Voltage Levels

U_n (kV)	U_m (kV)	$(U_m - U_n)/U_n$ %
765	800	4,58
400	420	5,00
330	346.5	5,00
275	300	9,09
220	245	11,36
132	145	9,85
88	100	13,63

66	72,5	9,85
44	48	9,09
33	36	9,09
22	24	9,09
11	12	9,09
Table 4: Target Voltages for Planning Purposes		
Minimum steady state voltage on any bus not supplying a <i>customer</i> With multiple feeder supplies:	0.95 U_n	
With single feeder supplies and after contingency for multiple feeder supplies:	0.90 U_n	
Maximum harmonic voltage caused by <i>customer</i> at <i>PCC</i> :	According to NRS 048	
Maximum negative sequence voltage caused by <i>customer</i> at <i>PCC</i> :	According to NRS 048	
Maximum voltage change due to load varying N times per hour:	$(4.5 \log_{10} n)\%$ of U_n	
Maximum voltage decrease for a 5% load increase at receiving end of system (without adjustment):	0.05 U_n	

ANNEXURE 4

SURVEYING, MONITORING AND TESTING FOR GENERATORS

1. Introduction

This section specifies the procedures to be followed in carrying out the surveying, monitoring or testing of to confirm the -

- (a) compliance by power stations with the Transmission Grid Code
- (b) provision by power stations of ancillary services which they are required or have agreed to provide.

2. Scope

This Annexure applies to generators.

3. Request for surveying, monitoring or testing

The system operator may at any time, although it may not do so more than twice in any calendar year in respect of any particular power station except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test, issue an instruction requiring a power station to carry out a test, at a time no sooner than 48 hours from the time that the instruction was issued, to demonstrate that the relevant power station complies with the Transmission Grid Code.

4. Ongoing monitoring of performance of unit

- (1) A generator must monitor each of its units during normal service to confirm ongoing compliance with the applicable parts of Chapter 3.
- (2) If a generator detects a deviation in its unit the generator must report the deviation to the system operator within five working days.
- (3) A generator must keep records -
 - (a) relating to the compliance by each of its units with each code of Chapter 3 applicable to that unit; and
 - (b) setting out the information that the system operator or transmission company reasonably requires for assessing power system performance including actual unit performance during abnormal conditions.
- (4) Within one month after the end of June and December, a generator must provide the system operator with a report detailing the compliance by each unit of the generator with every applicable code of Chapter 3 during the past six month period.
- (5) The template for purposes of subitem (4) is set out in Annexure 8.

5. Procedures

- (1) Unit protection system grid code requirement GCR 3

Parameter	Reference	
Protection function and setting integrity study		<p>APPLICABILITY AND FREQUENCY</p> <p>Prototype study: All new power stations coming on line or power stations where major refurbishment or upgrades of protection systems have taken place.</p> <p>Routine review: All power stations every five to six years.</p> <p>PURPOSE</p> <p>To ensure that the relevant protection functions in the power station is co-ordinated and aligned with the system requirements.</p> <p>PROCEDURE</p> <p>Prototype:</p> <ol style="list-style-type: none"> 1. Establish the system protection function and associated trip level requirements from the transmission company. 2. Derive protection functions and settings that match the power station plant, the transmission company plant and system requirements. 3. Confirm the stability of each protection function for all relevant system conditions. 4. Document the details of the trip levels, stability calculations for each Protection function. 5. Convert protection tripping levels for each protection function into per unit base. 6. Consolidate all settings in per unit base for all protection functions in one document 7. Derive actual relay dial setting details and document the relay setting sheet for all protection functions. 8. Document the position of each protection function on one single line diagram of the generating unit and associated connections. 9. Document the tripping functions for each tripping function on one tripping logic diagram. 10. Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base information the settings are based on, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers information into one document. 11. Submit to the transmission company for their acceptance and update. 12. Provide the transmission company with one original reference copy and one working copy. <p>Review:</p> <ol style="list-style-type: none"> 1. Review prototype 1 to 10 above. 2. Submit to the transmission company for their acceptance and update. 3. Provide the transmission company with one original reference copy and one working copy. <p>ACCEPTANCE CRITERIA</p> <p>All protection functions are set to meet the necessary protection requirements of the transmission system and power station plant with minimal margin. Optimal fault clearing times and maximum plant availability.</p> <p>Submit a report to the transmission company one month after commissioning for prototype study or five to six years for routine tests.</p>

Parameter	Reference	
Protection integrity tests		<p>APPLICABILITY</p> <p>Prototype test: All new power stations coming on line and all other power stations after major modifications or refurbishment of protection or related plant.</p> <p>Routine test of all power stations: five to six years or after major overhaul of plant.</p> <p>PURPOSE</p> <p>To confirm that the protection has been wired and function according to the specified.</p> <p>PROCEDURE</p> <ol style="list-style-type: none"> 1. Apply final settings as per agreed documentation to all protection functions. 2. With the generator unit off load and de-energized, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations. 3. Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV Breaker). Document all trip test responses. 4. Apply short circuits at all relevant protection zones and with generator at nominal speed excite generator slowly, record currents at all relevant protection functions, and confirm correct operation of all relevant Protection functions. Document all readings and responses. Remove all short circuits. 5. With the generator at nominal speed, excite generator slowly recording voltages on all relevant Protection functions. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses. <p>ACCEPTANCE CRITERIA</p> <p>All Protection functions fully operational and operate to required levels within the relay original equipment manufacturer (OEM) allowable tolerances.</p> <p>Measuring instrumentation used must be sufficiently accurate and calibrated to traceable standard.</p> <p>Submit a report to the transmission company one month after test.</p>

(2) Unit islanding capability grid code requirement GCR 4

Parameter	Reference	
Islanding		<p>APPLICABILITY</p> <p>Prototype test: For all other fossil and nuclear power stations</p> <p>Routine test: For stations that have contracted to island under the ancillary services agreement. 5-6 yearly or after modifications done to plant that may effect islanding capability</p> <p>Continuous monitoring: Where in the day to day running of the plant, a real condition arises where a generating unit is required to island, and the Islanding takes place successfully, and the islanding condition is sustained as specified under acceptance criteria below or is called to synchronize and complete synchronizing successfully it must be considered as a successful islanding test.</p> <p>PURPOSE</p> <p>To confirm that a generating units that have specified and/or contracted to provide an islanding service, complies. Islanding is the ability of a generating unit to suddenly disconnect from the transmission system by the opening the HV breaker, and automatically control all the necessary critical parameters sufficiently to maintain the turbine-generator at speed and excited and supplying its own auxiliary load. This islanded mode must be sustained for at least 20 minutes without tripping of the turbine, boiler, excitation system, or other systems critical to sustain an islanding condition.</p> <p>PROCEDURE</p> <ul style="list-style-type: none"> • Generating unit running at steady state conditions above 60% full load conditions. • All protection and control systems in normal operating conditions. • No special modifications to the plant for the purpose of the test, accept installation of monitoring equipment, is allowed. • The unit supplies all its own auxiliary load during the test • No operating is allowed for the first 5 minutes following the initiation of the islanding. • Equipment is connected to the generating unit that records critical parameters. The following minimum parameters is recorded: <ul style="list-style-type: none"> (a) turbine speed; (b) alternator load; (c) alternator voltage and current; (d) exciter voltage and current; (e) unit board voltage; (f) anticipatory device position, where installed; and (g) system frequency. • Initiation of the islanding is done by opening the HV Breaker. <p>ACCEPTANCE CRITERIA</p> <p>The turbine must settle at or close to its nominal speed, the excitation system must remain in automatic channel, supplying all the auxiliary load of the unit. The islanding condition must be sustained for at least 20 minutes.</p>

(3) Excitation system grid code requirement GCR 5

Parameter	Reference	
Excitation and setting integrity study		<p>APPLICABILITY AND FREQUENCY</p> <p>Prototype study: All new power stations coming on line or power stations where major refurbishment or upgrade of protection systems have taken place.</p> <p>Routine review: All power stations every five to six years.</p> <p>PURPOSE</p> <p>To ensure that the excitation systems in the power station is co-ordinated and aligned with the system requirements.</p> <p>PROCEDURE</p> <p>Prototype:</p> <ol style="list-style-type: none"> 1. Establish the system excitation system performance requirements from the transmission company. 2. Derive a suitable model for the excitation system according to IEEE421.5 or IEC 60034.16.2. Where necessary, non-standard models (non IEC or IEEE) must be created.. This may require frequency response and bode plot tests on the excitation system as described in IEEE 421.2.1990. 3. Submit the model to the transmission company for their acceptance. 4. Derive excitation system settings that match the power station plant, transmission system plant and system requirements. This includes the settings of all parts of the excitation system such as the chop-over limits and levels, limiters, Protection devices, alarms. 5. Confirm the stability of the excitation system for relevant excitation system operating conditions system conditions. 6. Document the details of the trip levels, stability calculations for each setting and function. 7. Convert settings for each function into per unit base and produce a high level dynamic performance model with actual settings in P.U. values. 8. Derive actual card setting details and document the relay setting sheet for all setting functions. 9. Produce a single line diagram or block diagram of all the functions in the excitation system and indicate signal source. 10. Document the tripping functions for each tripping on one tripping logic diagram. 11. Consolidate detail setting calculations, model, per unit setting sheets, relay setting sheets, plant base Information the settings are based on, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers Information into one document. 12. Submit to the transmission company for their acceptance and update. 13. Provide the transmission company with one original master copy and one working copy. <p>Review: Review prototype 1 to 10 above.</p>

		<p>Submit to the transmission company for their acceptance and update. Provide the transmission company with one original master copy and one working copy update if applicable.</p> <p>ACCEPTANCE CRITERIA</p> <p>Excitation system is set to meet the necessary control requirements in an optimized manner for the performance of the transmission system and power station plant. Excitation system operates stable both internally and on the network.</p> <p>Submit a report to the transmission company one month after commissioning for prototype study or five to six years for routine tests, within one month after due date expiry.</p>
Excitation response tests		<p>APPLICABILITY</p> <p>Prototype test: All new power stations coming on line and all other power stations after major modifications or refurbishment of protection or related plant.</p> <p>Routine test: All power stations 5 to 6 years or after major overhaul of plant.</p> <p>Prototype test: All new power stations coming on line and all other Power Stations after major modifications or refurbishment of Protection or related plant.</p> <p>Routine test: All power stations 5 to 6 years or after major overhaul of plant.</p> <p>PURPOSE</p> <p>To confirm that the excitation system performs as per the specified acceptance criteria below.</p> <p>PROCEDURE</p> <p>With the generator off line, carry out frequency scan or bode plot tests on all circuits in the excitation system critical to the performance of the excitation system.</p> <p>With the generator in the open circuit mode, carry out the large signal performance testing as described in IEEE 421.2 of 1990.</p> <p>With the generator connected to the network and loaded, determine time response, ceiling voltage and voltage response and carry out the small signal performance tests according to IEE 421.2.1990. Also carry out power system stabiliser tests and determine damping with and without power system stabiliser.</p> <p>Document all responses.</p> <p>ACCEPTANCE CRITERIA</p> <p>Excitation system meets the necessary control requirements in an optimised manner for the performance of the transmission system and power station plant as specified. Excitation system operates stable both internally and on the network. Power system stabilisers set for optimised damping.</p>

(4) Unit Reactive Power Capability Grid Code Requirement GCR 6

Parameter	Reference	
Reactive power capability		<p>APPLICABILITY</p> <p>Prototype test: All new power stations coming on line and all other power stations after major modifications or refurbishment of protection or related plant.</p> <p>PURPOSE</p> <p>To confirm that the reactive power capability specified are met.</p> <p>PROCEDURE</p> <p>The duration of the test will be for a period of up to 60 minutes during which period the system voltage at the grid entry point for the relevant generating unit will be maintained by the generator at the voltage specified by adjustment of reactive power on the remaining generating units, if necessary.</p> <p>ACCEPTANCE CRITERIA</p> <p>Generating unit will pass the test if it is within $\pm 5\%$ of the capability registered with the transmission company</p> <p>Submit a report to the transmission company one month after test.</p>

(5) Power station multiple unit trip grid code requirement GCR 7

Parameter	Reference	
Multiple unit tripping (MUT) tests, study and survey		<p>APPLICABILITY</p> <p>Prototype tests, study or survey:</p> <ul style="list-style-type: none"> • New power stations coming on line, items 1 to 5 below or • Power stations where major modifications or changes have been implemented on plant critical to multiple unit tripping. Applicable criteria 1 to 5 below. <p>Routine assessment: All power stations. Criterion 5 below. Annually</p> <p>Routine testing: All power stations. Every five to six years or after a major overhaul. Criteria 1 to 4 below.</p> <p>PURPOSE</p> <p>To confirm that a power station is not subjected to unreasonable risk of MUT as defined in connection code section 2.2.1.5.</p> <p>PROCEDURE AND ACCEPTANCE CRITERIA</p> <p>1. Emergency supply isolation test: On all emergency supplies (e.g. DC supplies) common to more than one generating unit, isolate supply for at least one second, with the unit running at full load under normal operating conditions. Tests are carried out on one unit at the time. Where two supplies feed one common load, isolation of one supply at a time would be sufficient. Confirm that the unit or part of the unit plant does not trip. No change in the unit output must take place. Document results.</p>

		<p>2. Disturbance on DC supply survey: On all DC supplies common to more than one generating unit, carry out a survey of the immunity of all devices that are part of tripping circuits, to supply voltage according to appropriate IEC standard. All devices on DC supplies common to more than one unit that form part of tripping circuits or that can cause tripping or Load Reduction on a unit must comply to the appropriate IEC standard. Document findings.</p> <p>3. Uninterruptible power supplies (UPS) integrity testing: On all UPS's supplying critical loads that can cause tripping of more than one generating unit within the time zones specified in 2.2.1.5, isolate the AC supply to the UPS for a period of at least 1 minute. Where two UPS's supply one common load, one UPS at a time can be isolated. Load equipment must resume normal operation. Document results.</p> <p>4. Earth mat integrity inspection and testing: Carry out an inspection and tests on all parts of the power station earth mat that is exposed to lightning surge entry and in close proximity to circuits vulnerable to damage that will result in tripping of more than one generating unit within the time zones specified in 2.2.1.5 (e.g. Chimney on fossil power stations or penstock on hydro power stations) Confirm that all the earthing and bonding is in place, and measure resistances to earth at bonding points.. Document findings and results.</p> <p>5. MUT risk assessment: Identify all power supplies, air supplies, water supplies, and other supplies or systems common to more than one generating unit than is likely to cause the tripping of more than one generating unit within the MUT time zones specified in section 2.2.1.5. Calculate the probability of all the Zone 1, Zone 2 and Zone 3 MUT risk areas for the power station. Document all findings listing all risks and probabilities.</p> <p>No unreasonable MUT items as listed in 2.2.1.5 must be present. Report to be submitted to the transmission company one month after testing. Routine studies, and survey reports to be submitted one month after expiry of due date.</p>
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(6) Governing system grid code requirements GCR 8

Parameter	Grid Code Reference	
Governing response tests		<p>APPLICABILITY</p> <p>Prototype test: All new power stations coming on line and all other power stations after major modifications or refurbishment of protection or related plant.</p> <p>Routine test: All units to be monitored continuously, additional tests may be requested by the system operator.</p> <p>PURPOSE</p> <p>Prove the unit is capable of the minimum requirements required for governing.</p>

		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. Frequency or speed deviation to be injected on the unit for 10 minutes. 2. Real power output of the unit is to be measured and recorded. <p>ACCEPTANCE CRITERIA</p> <p>Minimum requirements set out in codes 43 to 53 are met.</p>
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(7) Unit restart after station blackout capability grid code requirement GCR 9

Parameter	Reference	
Restart after station blackout Survey		<p>APPLICABILITY</p> <p>Prototype survey: Procedure 1 for new power stations or power stations where modifications have been carried out on plant critical to multiple unit restarting.</p> <p>Routine survey: All power stations. Procedure 2 every three months.</p> <p>PURPOSE</p> <p>To confirm that a power station can restart unit simultaneously to the criteria outlined in section 2.2.1.7 after a station blackout condition.</p> <p>PROCEDURE</p> <ol style="list-style-type: none"> 1. Plant capacity survey: <ul style="list-style-type: none"> • Identify all supply systems common to two or more systems (e.g. power supplies, crude oil, air, demin water) • Determine the quantity and supply rate required to simultaneously restart the number of units specified in section 2.2.1.7 • Document list of critical systems, required stock, study details and findings. 2. Survey of available stock: <ul style="list-style-type: none"> • For each of the applicable critical systems identified, document the average stock for the year, minimum stock and duration below critical stock levels. <p>ACCEPTANCE CRITERIA</p> <p>More than 95% of the time of the year, all stocks above critical levels.</p> <p>Report to be submitted to the transmission company one month after commissioning. Routine survey reports to be submitted one month after expiry of due date.</p>

(8) Power station black start capability grid code requirement GCR 10

Parameter	Reference	
Unit black starting		<p>APPLICABILITY</p> <p>Routine Test: Power stations that have contracted under the ancillary services to supply unit black start services. When called for by the transmission company but not more than once every two years</p> <p>PURPOSE</p> <p>Demonstrate that a black start unit has a black start capability.</p> <p>PROCEDURE</p> <ul style="list-style-type: none"> • The relevant generating unit must be synchronised and loaded; • All the auxiliary gas turbines and auxiliary diesel engines in the black start station in which that generating unit is situated, must be shutdown. • The generating unit must be de-loaded and de-synchronised and all alternating current electrical supplies to its auxiliaries must be disconnected. • The auxiliary gas turbine(s) or auxiliary diesel engine(s) to the relevant generating unit must be started, and must re-energise the unit board of the relevant generating unit. • The auxiliaries of the relevant generating unit must be fed by the auxiliary gas turbine(s) or auxiliary diesel engine(s), via the unit board, to enable the relevant generating unit to return to synchronous speed. • The relevant generating unit must be synchronised to the system but not loaded, unless the appropriate instruction has been given by the transmission company. <p>All black start tests must be carried out at the time specified by the transmission company in the notice given under 2.2.1.8 and must be undertaken in the presence of a reasonable number of representatives appointed and authorised by the transmission company, who must be given access to all information relevant to the black start test.</p> <p>ACCEPTANCE CRITERIA</p> <p>A black start station must fail a black start test if the black start test shows that it does not have a black start capability (i.e. if the relevant generating unit fails to be synchronised to the system within two hours of the auxiliary gas turbine(s) or auxiliary diesel engine(s) being required to start).</p> <p>Submit a report to the transmission company one month after test.</p>

Parameter	Reference	
Station black starting		<p>APPLICABILITY</p> <p>Routine test: All stations contracted under ancillary services to provide a station black start service. When called for by the transmission company but not more than once every two years</p> <p>PURPOSE</p> <p>Demonstrate that a black start station has a black start capability.</p> <p>PROCEDURE</p> <ul style="list-style-type: none"> • All generating units at the black start station, other than the generating unit on which the black start test is to be carried out, and all the auxiliary gas turbines and auxiliary diesel engines at the black start station, must be shutdown. • The relevant generating unit must be synchronised and loaded. • the relevant generating unit must be de-loaded and de-synchronised. • All external alternating current electrical supplies to the unit board of the relevant generating unit, and to the station board of the relevant black start station, must be disconnected. • An auxiliary gas turbine or auxiliary diesel engine at the black start station must be started, and must re-energise either directly, or via the station board, the unit board of the relevant generating unit. • The auxiliaries of the relevant generating unit must be fed by the auxiliary gas turbine(s) or auxiliary diesel engine(s), via the unit board, to enable the relevant generating unit to return to synchronous speed. • The relevant generating unit must be synchronised to the system but not loaded, unless the appropriate instruction has been given by the transmission company. <p>All black start tests must be carried out at the time specified by the transmission company in the notice given under 2.2.1.8 and must be undertaken in the presence of a reasonable number of representatives appointed and authorised by the Transmission company, who must be given access to all Information relevant to the Black Start Test.</p> <p>ACCEPTANCE CRITERIA</p> <p>A black start station must fail a black start test if the black start test shows that it does not have a black start capability (i.e. if the relevant generating unit fails to be synchronised to the system within two hours of the auxiliary gas turbine(s) or auxiliary diesel engine(s) being required to start).</p> <p>Submit a report to the transmission company one month after test.</p>

(9) Unit intermediate load capability grid code requirement GCR 11

Parameter	Grid Code Reference	
Intermediate load capability		<p>APPLICABILITY</p> <p>Prototype study: All new power stations coming on line or power stations where major refurbishment or upgrade of the unit have taken place.</p> <p>Routine test: All units to be monitored continuously, additional tests may be requested by the system operator.</p> <p>PURPOSE</p> <p>Prove unit can meet the minimum requirements of the Transmission Grid Code</p> <p>PROCEDURE</p> <ol style="list-style-type: none"> 1. A section of the unit is to be tripped that will cause a 15% of MCR reduction of the output of the Unit. Should nothing be found to induce this reduction a sudden reduction of the Unit output must be done manually. 2. The plant is to be monitored and recorded to ensure the plant continues to operate in a stable and controlled mode after the reduction. <p>ACCEPTANCE CRITERIA</p> <p>The unit must be in a stable and controlled mode after the trip or reduction in the Unit output.</p>

(10) External supply disturbance withstand capability grid code requirement GCR 12

Parameter	Reference	
Voltage and frequency deviation		<p>APPLICABILITY</p> <p>Prototype survey or test: new power stations coming on line or power stations where major modifications to plant that may be critical to system supply frequency or voltage magnitude deviations. Criteria 1 to 4 for plants using Dip Proofing Inverters (DPI)</p> <p>Routine testing and survey: All power stations. Review items 1 to 3 every 5 to 6 years. Carry out item 5 every 5 to 6 years.</p> <p>PURPOSE</p> <p>To confirm that the power station and its auxiliary supply loads conforms to the requirements of supply frequency and voltage magnitude deviations as specified (to be determined).</p> <p>SCOPE OF PLANT OR SYSTEMS</p> <p>Critical plant: Equipment or systems that is likely to cause tripping of a unit, parts of a unit or that is likely to cause a multiple unit trip (MUT).</p>

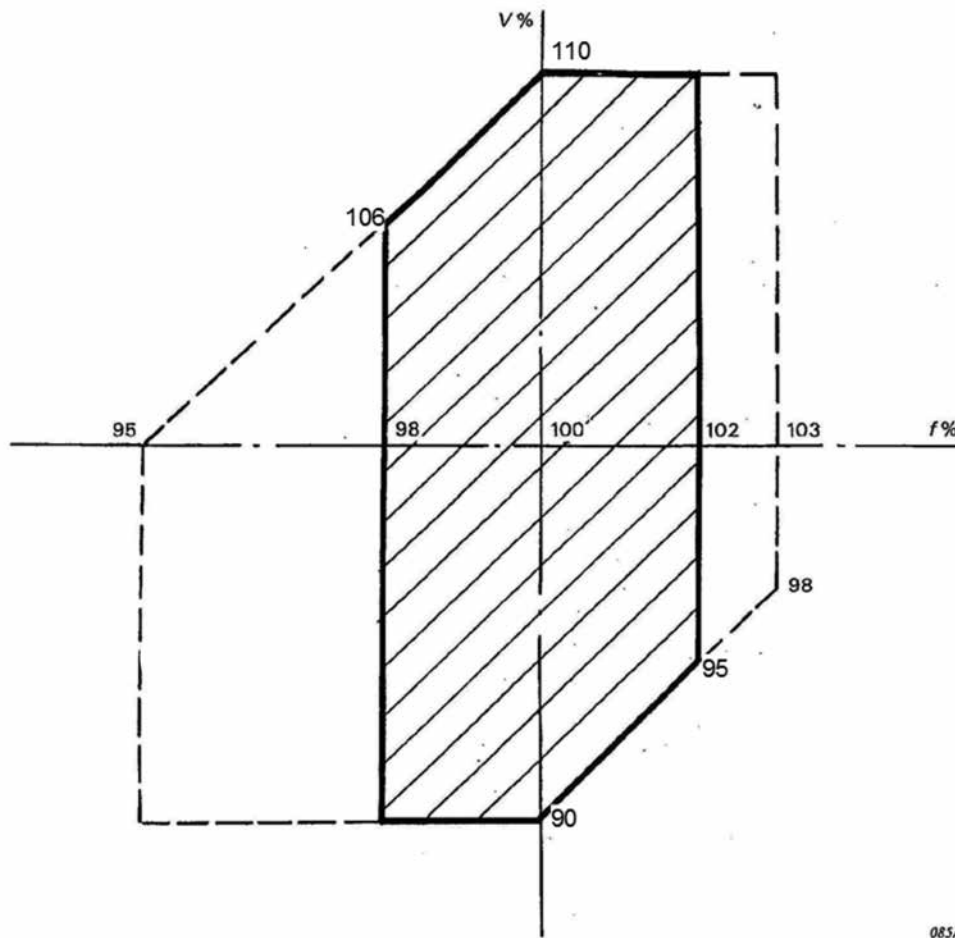
	<p>PROCEDURE AND ACCEPTANCE CRITERIA</p> <p>1. Frequency deviation survey: Carry out a survey on the capability of critical plant confirming that it will resume normal operation for frequency deviations as defined figure 2.2.1.6. Document findings.</p> <p>A generating unit or power station must not trip or unduly reduce load for system frequency changes in the range specified in 2.2.1.6.</p> <p>2. Voltage magnitude deviation survey:</p> <p>Carry out a survey on the capability of critical plant confirming that it will resume normal operation for voltage deviations as defined in 2.2.1.6. Document Findings. Also consider protection and other tripping functions on critical plant. Document all findings.</p> <p>A generating unit or power station must not trip or unduly reduce load for system voltage changes in the range specified in 2.2.1.6.</p> <p>3. Dip proofing inverter integrity testing:</p> <ul style="list-style-type: none"> • Generating unit must be off load. Relevant board isolated and earthed. For outside or central plant, section of plant must be off boards off and isolated. • Injection test DPIs according to OEM requirements. DPI must be capable of producing the VA Output and change-over time faster than that specified by the OEM. Every five years on every critical board. • Isolate all Drives on the board. • Select all drives to manual or local control. • Supply an independent AC supply to the input of the DPI. • Close the contractors of drives. • Subject the DPI supply to an interruption of 0.5 s. <p>Document all results.</p> <p>All contractors must remain closed.</p> <p>Report to be submitted to the transmission company one month after testing. Routine studies, and survey reports to be submitted one month after expiry of due date.</p>
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(11) Unit load and de-loading rate capability grid code requirements GCR 13

Parameter	Grid Code Reference	
Loading and de-loading rates.		<p>TYPE</p> <p>Prototype study: All new power stations coming on line or power stations where major refurbishment or upgrade of the unit have taken place.</p> <p>Routine test: All units to be monitored continuously, additional tests may be requested by the system operator.</p> <p>PURPOSE</p> <p>Prove unit can meet the minimum requirements of the Transmission Grid Code.</p> <p>PROCEDURE</p> <ol style="list-style-type: none"> 1. The Unit is to be ramped up and down. 2. The plant is to be monitored and recorded to ensure the plant continues to operate in a stable and controlled mode during and after the ramps. <p>ACCEPTANCE CRITERIA</p> <p>The unit must be ramped up and down in a stable and controlled mode and must meet the minimum requirements of the Transmission Grid Code.</p>

ANNEXURE 5

VOLTAGE TOLERANCES FOR VARIOUS FREQUENCY RANGES



085/88

ANNEXURE 6

TABLE 1: SELECTION OF DEAD LINE CHARGING END OF THE LINE

End A End B	<i>Substation FL<10kA</i>	<i>Substation FL>10kA</i>	<i>Power Station</i>
<i>Substation FL<10kA</i>	<i>Substation with higher FL</i>	<i>Substation A</i>	<i>Substation B</i>
<i>Substation FL>10kA</i>	<i>Substation B</i>	<i>Substation with lower FL</i>	<i>Substation B</i>
<i>Power Station</i>	<i>Substation A</i>	<i>Substation A</i>	<i>Power Station with lower FL</i>

ANNEXURE 7

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).

- (1) 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.
- (2) The Recipient agrees to disclose the Information only to persons who are in his or her permanent employ, and who require access to the Information to perform their duties in respect of the Work on behalf of the Client.
- (3) Persons other than those described in Clause 2 above, including but not restricted to temporary employees, subcontractors, and sub-consultants, shall enter into separate Confidentiality Agreements with the Information Owner prior to receiving the Information.
- (4) The Recipient undertakes to use the Information only to perform the Work on behalf of the Client, and for no other purpose whatsoever.
- (5) On completion of the Work, the Recipient shall at his or her own expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him by the Information Owner. The Recipient shall furthermore ensure that all duplicate copies of the Information in his or her, or his or her employees', possession (electronic as well as hard copy format) are destroyed.
- (6) The Recipient shall take all reasonable measures to protect the Security and integrity of the Information.
- (7) If requested to do so by the Information Owner, the Recipient shall forthwith at his or her expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him by the Information Owner. The Recipient shall furthermore ensure that all duplicate copies of the Information in his or her, or his or her employees', possession (electronic as well as hard copy format) are destroyed.

- (8) The Recipient shall report any leak of the Information, howsoever caused, to the Information Owner as soon as practicable after he becomes aware of the leak, and shall 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

.....

ANNEXURE 8

Distributor and end-use customer data

Unless otherwise indicated, the following information shall be supplied to the transmission company, prior to connection and then updated as and when changes occur.

1. Demand data

Connection capacity	Connection capacity required (MW)
Measured and forecast data (annually)	For each <i>Point of Supply</i> , the information required is as follows: <ul style="list-style-type: none"> • A 5-year demand forecast. (See Annexure 15). • A description setting out the basis for the forecast. • The season of peak demand • Quantification of the estimated impact of embedded generation. (See Annexure 15) • A 10-year demand estimate
User network data	<ul style="list-style-type: none"> • Electrical single-line diagram of user network to a level of detail to be agreed with the service- providers, including the electrical characteristics of circuits and equipment (R, X, B, R0, X0, B0, continuous and probabilistic ratings). • Contribution from <i>customer</i> network to a three-phase short circuit at <i>Point of Connection</i>. • Connection details of all <i>customer</i> transformers, shunt capacitors, shunt reactors etc. connected to the secondary voltage levels of the <i>customer</i> connected the <i>TS</i>. (the requirement here is for <i>data</i> pertaining to the network connecting shunt capacitors, harmonic filters, reactors, SVCs, etc. to the <i>Point of Supply</i> for purposes of conducting harmonic resonance studies.) • Electrical characteristics of all circuits and equipment at a voltage lower than secondary voltage levels of the <i>customer</i> connected the <i>TS</i> that may form a closed tie between two connection points on the <i>TS</i>.
Standby supply data (annually)	The following information is required for each <i>distributor</i> and <i>end-use customer</i> that can take supply from more than one supply point: <ul style="list-style-type: none"> • Source of standby supply (alternative supply point(s)) • Standby capacity required (MW)
General information	For each new connection from a <i>distributor</i> or <i>end-use customer</i> , the following information is required: <ul style="list-style-type: none"> • Number and type of switch bays required • Load build-up curve (in the case of new end-user plant) • Supply date (start of load build-up) • Temporary construction supply requirements • Load type (e.g. <i>ARC</i> furnaces, rectifiers, rolling mills, residential, commercial, etc.) • Annual load factor • Power factor (including details of harmonic filters and power factor correction capacitors) Special requirements (e.g. quality of supply) Other information reasonably required by the service-providers to provide the <i>customer</i> with an appropriate supply (e.g. pollution emission levels for insulation design)
Disturbing loads	Description of any load on the power system that could adversely affect the <i>System Operator</i> target conditions for power quality and the variation in the power quality that can be expected at the point connected to the <i>TS</i> . (The areas of concern here are, firstly, motors with starting currents referred back to the nominal voltage at the <i>Point of Supply</i> exceeding 5% of the fault level at the <i>Point of Supply</i> and secondly, <i>ARC</i> furnaces likely to produce <i>flicker</i> levels at the <i>Point of Supply</i> in excess of the limits specified in NRS048. The size limit for <i>ARC</i> furnaces is subject to local conditions in respect of fault level at the <i>Point of Supply</i> and background <i>flicker</i> produced by other <i>ARC</i> furnaces.)

2. Transmission system connected transformer data

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		A
Transformer rating		MVA _{Trans}
Transformer tertiary rating		MVA
Transformer nominal LV voltage		kV
Transformer nominal tertiary voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		HV/MV/LV/None (Delete what is not applicable)
Transformer ratio at all transformer taps		
Transformer Impedance (resistance R and reactance X) at all taps	R+jX	% on rating MVA _{Trans}
For three-winding transformers, where there are external connections to all three windings, the impedance (resistance R and reactance X) between each pair of windings is required, measured with the third set of terminals open-circuit.	Z_{HVMV} , Z_{HVLV} & Z_{MVLV}	% on rating MVA _{Trans} % on rating MVA _{Trans} % on rating MVA _{Trans}
Transformer zero sequence impedances at nominal tap		
Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals open-circuit.	Z_{HT0}	Ohm
Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals short-circuited to the neutral.	Z_{HL0}	Ohm
Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal, with the HV terminals open-circuit.	Z_{LT0}	Ohm
Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal, with the HV terminals short-circuited to the neutral.	Z_{LH0}	Ohm
Zero phase sequence leakage impedance measured between the HV terminals (shorted) and the LV terminals (shorted), with the Delta winding closed.	Z_{L0}	Ohm
Earthing arrangement, including LV neutral earthing resistance and reactance core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

Transformer test certificates, from which actual technical detail can be extracted as required, are to be supplied on request.

3. Shunt capacitor or reactor data requirements

- (1) For each shunt capacitor or reactor or power factor correction equipment or harmonic filters with a rating in excess of 1 MVA_r connected to or capable of being connected to a *customer* network, the *customer* shall inform the *Transco* and, if required, shall provide the *Transco* with the specific shunt capacitor or reactor *data* as well as network details necessary to perform primarily harmonic resonance studies. The *customer* shall inform the *Transco* of his intention to extend or modify this equipment.

- (2) If any *Participant* finds that a capacitor bank of 1MVA_r or less is likely to cause harmonic resonance problems on the *TS*, he shall inform the *Transco*. The 1MVA_r minimum size limit shall thereafter be waived in respect of the affected network for information reporting purposes in respect of this code, and the *Transco* shall inform the affected *Participants* of this fact and request the additional *data*. If the affected network is modified or reinforced to the extent that capacitor banks of 1 MVA_r or less no longer cause harmonic resonance problems on the *TS*, the *Transco* shall inform the affected *Participants* that information reporting requirements have returned to normal.
- (3) Any *Party* to this code investigating a complaint about harmonic distortion, shall have the right to request such additional information (including, but not restricted to, *data* from harmonic distortion measuring devices) from parties in the vicinity of the source of the complaint as may reasonably be required to complete the investigation.

Shunt capacitor or reactor rating	Rating (MVA _r)
Reactor/capacitor/harmonic filter	(delete what is not applicable)
Location (station name)	
Voltage rating	kV
Resistance/reactance/susceptance of all components of the capacitor or reactor bank	
Fixed or switched	
If switched	Control details (manual, time, load, voltage, etc.)
If automatic control	Details of settings. If under <i>FACTS</i> device control (e.g. <i>SVC</i>), which device?

4. Series capacitor or reactor data requirements

- (1) Series capacitors are installed in long *Transmission* lines to increase load transfer capability.
- (2) Series reactors are installed to limit fault levels, or to balance load sharing between circuits operated in parallel that would otherwise not share load equitably, or to balance load sharing on an interconnected network.

Reactor/capacitor	(Delete what is not applicable)
Location (specify <i>Substation</i> bay where applicable)	
Voltage rating	kV
Impedance rating	Ohm or MVA _r
Current rating (continuous and <i>emergency</i> , maximum times for <i>emergency</i> ratings)	Continuous: A Hours A Hours A Hours A

- (3) Note: if a series capacitor or reactor is located in a dedicated reactor or capacitor station (i.e. a *Substation* built to hold only the series reactor or capacitor), the lines or cables linking it to each remote end *Substation* must be specified as separate circuits under line or cable *data*.

5. FACTS devices and HVDC data

5.1 FACTS devices

- (1) FACTS devices enable system parameters (voltage, current, power flow) to be accurately controlled in real time. Because of their cost, they are generally used only if cheaper, more conventional, solutions cannot deliver the required functionality.
- (2) Applications requiring rapid control capability include the following:
 - (a) Voltage regulation following loss of a system component, generation, large load, or HVDC link disturbance;
 - (b) automatic reclosing cycle furnace voltage flicker mitigation;
 - (c) Negative phase sequence voltage compensation;
 - (d) Sub-Synchronous Resonance (SSR) damping;
 - (e) Machine transient stability enhancement;
 - (f) System load transfer capability enhancement; and
 - (g) Load sharing control in interconnected, deregulated, networks.
- (3) The most commonly used *FACTS* device is the *SVC* (static Var compensator). Other *FACTS* devices made possible by advances in power electronics and control systems include STATCON (static condenser), TCSC (thyristor controlled series capacitor), thyristor controlled tap changer, thyristor controlled phase shifter, BES (battery energy storage), and UPFC (unified power controller). The common factor is rapid control capability.
- (4) Because *FACTS* devices are purpose-designed for their specific applications, the following *data* is required:

Name	Station, HV voltage, device number
Type	(SVC, STATCON, TCSC, etc.)
Configuration: Provide a single line diagram showing all HV components and their MVA/MVAr and voltage ratings, with all controlled components identified as such.	
Control system: Provide a block diagram of the control system suitable for dynamics modelling.	
Primary control mode	Voltage control, automatic reclosing cycle furnace flicker mitigation, negative phase sequence voltage control, etc.

- (5) Customers are required to perform, or cause to be performed, harmonic studies to ensure that their installation does not excite harmonic resonance, and that harmonic distortion levels at the PCC with the TS do not exceed the limits specified in NRS048.

5.2 HVDC

- (1) Strictly speaking, HVDC is a form of *FACTS* device because of the rapid control capabilities. However, HVDC is treated separately because its primary function is the *Transmission* of real power.

- (2) HVDC is used to connect two systems that are not necessarily interconnected via the AC network (and thus in synchronism), or even at the same nominal frequency.
- (3) Customers wishing to connect HVDC systems to the TS shall supply a single line diagram showing all HV plant (including valve bridges) forming part of the HVDC system, plus additional HV plant required for its proper operation, e.g. harmonic filters, synchronous condensers, FACTS devices, etc. Customers and the Transco shall cooperate in performing, or causing to be performed, studies to determine network strengthening requirements needed to accommodate the HVDC system without violating the planning criteria specified in the Network Code. In addition, customers shall thereafter perform, or cause to be performed, studies to demonstrate that the proposed HVDC system does not cause exceedance of QOS parameters specified in NRS048, and where applicable shall specify what additional HV plant will be required to ensure compliance with NRS048.

6. Information on customer networks

- (1) If a customer will have two or more points of supply from the TS, including the one applied for, the customer shall specify the amount of load to be transferred from existing points of supply to the new one under normal conditions as well as under contingencies. The same requirement applies to any embedded generators within the customer's network, since they affect fault levels as well as net load on the system.
- (2) The customer shall also specify whether he intends to interconnect two or more Transmission points of supply via his network. In such circumstances the customer shall provide detailed information on the lines and cables used.
- (3) Where a circuit consists of two or more segments of different characteristics (different overhead line tower and/or conductor bundle types and/or underground cable types), each section shall be specified separately.

7. Overhead line data

	Units
Line description	Name ("from" Busbar, "to" Busbar, circuit number and, where applicable, line section number numbered from the "from" bus end)
Line voltage (specify separately for dual voltage multi-circuit lines)	kV
Single / double / multiple circuit	
Standard suspension tower information (to confirm impedance): Supply copy of tower drawing, or sketch drawing showing co-ordinates of shield wire and phase conductor bundle attachment points relative to tower centre line and ground level at nominal tower height.	
Phase sub-conductor type (per circuit)	
Number of sub-conductors per phase conductor bundle	
Sub-conductor spacing, if applicable (supply sketch showing phase conductor bundle geometry and attachment point)	mm
Number of earth wires	
Earth wire description	
Line length	km
Conductor parameters (R, X, B, R0, X0, B0)	Ohmic values or P.U. on 100MVA base (specify)
Conductor normal and emergency ratings	Ampere or 3 phase MVA at nominal voltage

8. Cable data

Cable description	Name (“from” <i>Busbar</i> , “to” <i>Busbar</i> , circuit number, and where applicable, line section number numbered from the “from” bus end)
Voltage rating	kV
Type (copper/aluminium)	(Delete what is not applicable)
Size	mm ²
Impedance (R, X, B, R ₀ , X ₀ , B ₀)	Ohms or <i>P.U.</i> on 100MVA base (specify)
Length	km
Continuous and (where applicable) <i>emergency</i> current rating and time limit	Amp or <i>MVA</i> at nominal voltage (specify), hours maximum at <i>emergency</i> rating

ANNEXURE 9

Generator planning data

Unless otherwise indicated, the following information shall be provided to the transmission company prior to connection and then updated as and when changes occur.

1. Power Station data

Generator name	
Power Station name	
Number of units	
Primary fuel type / prime mover	For example gas, hydro, fossil or nuclear
Secondary fuel type	For example oil
Capacity requirement	Generation sent-out connection capacity required (<i>MW</i>)
“Restart after station blackout” capacity	Provide a document containing the following: Start-up time for the first <i>Generating Unit</i> (time from restart initiation to synchronize) and each of the following units assuming that restarting of units will be staggered.
Black starting capacity	A document stating the number of units that can be black started at the same time, preparation time for the first <i>Generating Unit</i> black starting restarting time for the first <i>Generating Unit</i> , and restating time for the rest of the units.
Partial load rejection capability	A description of the amount of load the <i>Generating Unit</i> can automatically govern back, without any restrictions, as a function of the load at the point of <i>governing</i> initiation.
Multiple generating unit tripping (<i>MUT</i>) risks	A document outlining all systems common to more than one <i>Generating Unit</i> that is likely to cause a <i>MUT</i> . Discuss the measures taken to reduce the risk of <i>MUT</i> .

2. Generating unit data

Generating Unit number	
Capacity	<i>Generating Unit</i> capacity (<i>MW</i>)

	Units
Normal maximum continuous generation capacity:	<i>MW</i>
Normal maximum continuous sent out capacity	<i>MW</i>
<i>Generating Unit</i> auxiliary active load	<i>MW</i>
<i>Generating Unit</i> auxiliary reactive load	MVA _r
Maximum (EL1) generating capacity	<i>MW</i>
Maximum (EL2) sent out capacity	<i>MW</i>
Normal minimum continuous generating capacity	<i>MW</i>
Normal minimum continuous sent out capacity	<i>MW</i>
<i>Generator</i> rating (Mbase)	<i>MVA</i>
Normal maximum lagging power factor	MVA _r
Normal maximum leading power factor	MVA _r
Governor droop	
Forbidden loading zones	<i>MW</i>
Terminal voltage adjustment range	kV
Short circuit ratio	
Rated stator current	Amp

Time to synchronise from warm	Hour
Time to synchronise from cold	Hour
Minimum up-time	Hour
Minimum down-time	Hour
Normal loading rate	MW/min
Normal de-loading rate	MW/min
Can the <i>generator</i> start on each fuel?	
Ability to change fuels on-load	
Available modes (lean burn etc.)	
Time to change modes on-load	
Control range for secondary <i>frequency</i> regulation operation	MW
Partial load rejection capability	% MW name plate rating
Minimum time <i>Generating Unit</i> operates in island mode	Hour
Maximum time <i>Generating Unit</i> operates in island mode	Hour

Description	Data
Capability chart showing full range of operating capability of the <i>generator</i> , including thermal and excitation limits	Diagram
Systems that are common and can cause a multiple <i>Generating Unit</i> trip	Description
Open circuit magnetisation curves	Graph
Short circuit characteristic	Graph
Zero power factor curve	Graph
V curves	Diagram

Documents	Description
<i>Protection</i> setting document	<p>A document agreed and signed by the <i>System Operator</i> containing the following:</p> <ul style="list-style-type: none"> • A section defining the base values and per <i>Generating Unit</i> values to be used • A single line diagram showing all the <i>Protection</i> functions and sources of current and voltage signals • A <i>Protection</i> tripping diagram(s) showing all the <i>Protection</i> functions and associated tripping logic and tripping functions • A detailed description of setting calculation for each <i>Protection</i> setting, discussion on <i>Protection</i> function stability calculations, and detailed dial settings on the <i>Protection</i> relay in order to achieve the required setting • A section containing a summary of all <i>Protection</i> settings on a per <i>Generating Unit</i> basis • A section containing a summary for each of the <i>Protection</i> relay dial settings/programming details • An annex containing plant information <i>data</i> (e.g. <i>OEM data</i>) on which the settings are based • An annex containing <i>OEM</i> information sheets or documents describing how the <i>Protection</i> relays function

Excitation setting document	<p>A document agreed and signed by the <i>System Operator</i> containing the following:</p> <ul style="list-style-type: none"> • A section defining the base values and per <i>Generating Unit</i> values to be used • A single line diagram showing all the excitation system functions and all the related <i>Protection</i> tripping functions • An excitation system transfer function block diagram in accordance with IEEE or <i>IEC</i> standard models • A detailed description of setting calculation for each of the excitation system functions, discussion on function stability calculations, and detailed dial settings on the excitation system in order to achieve the required setting • A section containing a summary of all settings on a per <i>Generating Unit</i> basis • A section containing a summary for each of the excitation system dial settings/programming details. • An annex containing plant information <i>data</i> (e.g. <i>OEM data</i>) on which the settings are based • An annex containing <i>OEM</i> information sheets or documents describing the performance of the overall excitation system and each excitation function for which a setting is derived
Governor setting document	<p>A document agreed and signed by the <i>System Operator</i> containing the following:</p> <ul style="list-style-type: none"> • A section defining the base values and per <i>Generating Unit</i> values to be used • A single line diagram showing all the excitation system functions and all the related <i>Protection</i> tripping functions • An excitation system transfer function block diagram in accordance with IEEE standard models • A detailed description of setting calculation for each of the governor system functions, discussion on function stability calculations, and detailed dial settings on the governor system in order to achieve the required setting • A section containing a summary of all settings on a per <i>Generating Unit</i> basis • A section containing a summary for each of the governor system dial settings/programming details • An annex containing plant information <i>data</i> (e.g. <i>OEM data</i>) on which the settings are based • An annex containing <i>OEM</i> information sheets or documents describing the performance of the overall governor system and each governor function for which a setting is derived

3. Reserve capability

The *generator* shall provide the *System Operator* with the reserve capability of each *Generating Unit* at each *Power Station*. The reserve capability shall be indicated as per each reserve category: instantaneous reserve, *Regulating Reserve*, *emergency* reserve, 10 minute reserve and supplemental reserve.

4. Generating unit parameters

	Symbol	Units
Direct axis synchronous reactance	X_d	% on rating
Direct axis transient reactance saturated	$X'_{d_{sat}}$	% on rating
Direct axis transient reactance unsaturated	$X'_{d_{unsat}}$	% on rating
Sub-transient reactance unsaturated	$X''_d = X''_q$	% on rating
Quad axis synchronous reactance	X_q	% on rating

Quad axis transient reactance unsaturated	$X'_{q_{unsat}}$	% on rating
Negative phase sequence synchronous reactance	X_2	% on rating
Zero phase sequence reactance	X_{0q}	% on rating
Turbine <i>generator</i> inertia constant for entire rotating mass	H	MW s/MVA
Stator resistance	Ra	% on rating
Stator leakage reactance	X_L	% on rating
Poiter reactance	X_P	% on rating
<i>Generator</i> time constants:		
· Direct axis open-circuit transient	Tdo'	sec
· Direct axis open-circuit sub-transient	Tdo''	sec
· Quad axis open-circuit transient	Tqo'	sec
· Quad axis open-circuit sub-transient	Tqo''	sec
· Direct axis short-circuit transient	Td'	sec
· Direct axis short-circuit sub-transient	Td''	sec
· Quad axis short-circuit transient	Tq'	sec
· Quad axis short-circuit sub-transient	Tq''	sec
Speed damping	D	
Saturation ratio at 1 pu terminal voltage	S(1.0)	
Saturation ratio at 1.2 pu terminal voltage	S(1.2)	

5. Excitation system

- (1) The *generator* shall fill in the following parameters or supply a Laplace-domain control block diagram in accordance with IEEE or IEC standard excitation models (or as otherwise agreed with the *System Operator*) completely specifying all time constants and gains to fully explain the transfer function from the compensator or *Generating Unit* terminal voltage and field current to *Generating Unit* field voltage. Customers shall perform, or cause to be performed, small signal dynamic studies to ensure that the proposed excitation system and turbine governor do not cause dynamic instability. Where applicable, a PSS (power system stabiliser) shall be included in the excitation system to ensure proper tuning of the excitation system for stability purposes.

	Symbol	Units
Excitation system type (<i>AC</i> or <i>DC</i>)		Text
Excitation feeding arrangement (solid or shunt)		Text
Excitation system filter time constant	Tr	sec
Excitation system lead time constant	Tc	sec
Excitation system lag time constant	Tb	sec
Excitation system controller gain	Ka	
Excitation system controller lag time constant	Ta	sec
Excitation system maximum controller output	Vmax	P.U.
Excitation system minimum controller output	Vmin	P.U.
Excitation system regulation factor	Kc	
Excitation system rate feedback gain	Kf	
Excitation system rate feedback time constant	Tf	sec

6. Speed governor system, turbine and boiler models

The *generator* shall supply a Laplace domain control block diagram in accordance with IEEE standard prime mover models for thermal and hydro units (or as otherwise agreed with the *Transco*), fully specifying all time constants and gains to fully explain the transfer function for the governor, turbine, penstocks and control systems in relation to *frequency* deviations and set-point operation.

7. Control devices and protection relays

The *generator* should supply any additional Laplace domain control diagrams for any outstanding control devices (including power system stabilisers) or special *Protection* relays in the *Generating Unit* that automatically impinge on its operating characteristics within 30 seconds following a system disturbance and that have a minimum time constant of at least 0,02 seconds.

8. Pumped storage

	Symbol	Units
Reservoir capacity		MWh pumping
Max pumping capacity		MW
Min pumping capacity		MW
Efficiency (generating/pumping ratio)		%

9. Generating unit step-up transformer

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		Amps
Transformer rating		MVA _{Trans}
Transformer nominal LV voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		
Transformer ratio at all transformer taps		
Transformer impedance at all taps (For three winding transformers the HV/LV1, HV/LV2 and LV1/LV2 impedances together with associated bases shall be provided)		% on rating MVA _{Trans}
Transformer zero sequence impedance at nominal tap	Z_0	Ohm
Earthing arrangement, including neutral earthing resistance and reactance		
Core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

10. Generating unit forecast data

The *generator* shall provide the *Transco* with expected maintenance requirements, in weeks per annum, for each *Generating Unit* at a *Power Station*.

11. Mothballing of generating plant

Mothballing of generating plant is the withdrawal of plant from commercial service for six *Months* or longer, with the intention of returning it to commercial service at a later date. Mothballing can have a profound impact on the operation and integrity of the *TS*. Customers wishing to mothball generating plant shall supply the *Transco* with the following information:

<i>Generator name</i>	
<i>Power Station name</i>	
<i>Generating Unit number</i>	
Date withdrawn	Date <i>Generating Unit</i> is to be withdrawn from commercial service
Return to commercial service	Envisaged return to service date (re-commissioning tests completed and <i>Generating Unit</i> available for commercial service)
Auxiliary power requirements	

12. Return to service of mothballed generating plant

Once the *customer* has decided to return mothballed generating plant to service, the *Transco* requires the information specified for new connections.

13. Decommissioning of generating plant

Decommissioning of plant is the permanent withdrawal from service of generating plant. The *Transco* requires the following with a one-year notice period:

<i>Generator name</i>	
<i>Power Station name</i>	
<i>Generating Unit number</i>	
Date to be removed from commercial service	
Auxiliary supplies required for dismantling and demolition	kVA, point at which supply is require, duration

ANNEXURE 11

Operational data

- (1) This Annexure specifies the *data* format to be used by the *SCADA* system for the mapping of *RTU data* into the *SCADA* database. The *data* base has a definition for each electrical configuration (ELC) or electrical object in the station. Each ELC definition specifies a different ELC type, e.g. transformers, units, feeders, etc, and is accompanied by a picture showing the ELC and all its associated devices as they would be indicated on the *System Operator* operational one-line displays. In each instance, the picture defines the primary devices and is followed by the points belonging to each device.
- (2) Description of table column headings used in this section:

Device	01_State	10_State	Category	Type	Control
--------	----------	----------	----------	------	---------

Device Gives the name of the device and acts as a collector of all point information belonging to the device. Each binary status point can be mapped to one or two binary bits. In the case of a breaker or isolator, the state is reported via two bits. In the case of single-bit alarm points, only one bit is used to report the state of the indication.

01_state This is the **alarm** state of the point.

10_state This is the **normal** state of the point.

In the table below the TYPE column indicates the number of bits used to report the state of the point in question.

For single-bit points please ignore the left-hand 0 or 1 value in the headings "01-State" and "10-State".

Where an indication uses two bits to report the state, the right-hand bit is used report that the state is OPEN and the left-hand bit to report the state when it is CLOSED. Thus an open condition will be "01" and a closed state will be "10".

It is thus illogical for a device to have a permanent value of either "00" or "11". However, if the device is in transit between "01" and "10" then a temporary value of "00" is possible. The *SCADA* system reports a state of "00" as "In transit", which will normally only be seen on slow-moving devices such as isolators.

Category Defines the category the point belongs to: Health, Main *Protection*, Back-up *Protection* or *Information*.

Classical alarm systems attempt to set priorities on alarm points. However, the priority of a point changes as the system changes, which means having a fixed priority is not useful. As an alternative, the approach used here is to assign the point to the area that is affected by the indication. In this case we have four areas, namely:

Health	All alarm indications that refer to the health of the primary or secondary plant are assigned to this category.
Main <i>Protection</i>	All <i>Protection</i> activity that is triggered by the Main 1 <i>Protection</i> circuits is assigned to this category.

<i>Backup Protection</i>	Where back-up <i>Protection</i> is installed, such as on transformers, or where Main 2 <i>Protection</i> is used, these alarms are assigned to this category.
<i>Information</i>	Pure state change <i>data</i> such the state of a breaker or isolator are assigned to this category. As such, no alarming is associated with these points – the <i>data</i> presented is pure information.

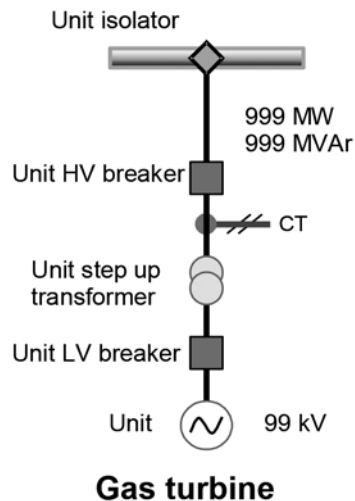
Type Indicates the type of point – single-bit, double-bit, analogue or binary change detection.

Control Indicates if there is a supervisory control associated with the point

1. Generator

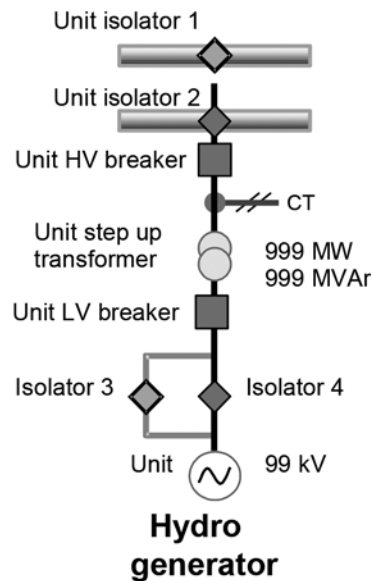
The generator shall install operational measurements to specification from the system operator so as to provide continuous operational information for both real time and recording purposes in relation to each generating unit at each power station in respect of the following:

(1) Gas turbines



<i>Generating Unit Isolator</i>	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit isolator state</i>	Open	Closed	Info	Double	False
<i>Generating Unit HV Breaker</i>	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
<i>Protection unhealthy</i>	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
<i>Generating Unit breaker state</i>	Closed	Tripped	Info	Double	False
Current Transformer	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
<i>Generating Unit Step Up Transformer</i>	01_State	10_State	Category	Type	Control

Reactive power			Info	Analogue	False
Active power			Info	Analogue	False
<i>Generating Unit</i> LV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating Unit breaker state	Closed	Tripped	Info	Double	False
<i>Generating Unit</i>	01_State	10_State	Category	Type	Control
Engine A	Ready	Not ready	Health	Single	False
Engine B	Ready	Not ready	Health	Single	False
Frequency			Info	Analogue	False
<i>Generating Unit</i> start not ready	Alarm	Normal	Health	Single	False
Remote control	On	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	False
Sequence starting	Auto	Manual	Info	Single	False
Stator voltage			Info	Analogue	False
Supervisory	Isolated	Off	Info	Single	False
Under-frequency start	Armed	Off	Health	Single	False
Generating Unit at standstill	Yes	Normal	Info	Single	True
<i>Generating Unit</i> auto load to base	Yes	No	Info	Single	True
<i>Generating Unit</i> auto load to minimum	Yes	No	Info	Single	True
<i>Generating Unit</i> auto load to peak	Yes	No	Info	Single	True
<i>Generating Unit</i> failed to start	Alarm	Normal	Health	Single	False
Generating Unit voltage			Info	Analogue	False
<i>Generating Unit</i> in generation mode	Yes	No	Info	Single	True
Generating Unit in SCO mode	Yes	No	Info	Single	True
Generating Unit load rate	Fast	Slow	Info	Single	True
Generating Unit loading mode	Auto	Manual	Info	Single	False
<i>Generating Unit</i> reactive power generated			Info	Analogue	False
<i>Generating Unit</i> reactive power sent out			Info	Analogue	False
<i>Generating Unit</i> active power generated			Info	Analogue	False
<i>Generating Unit</i> active power sent out			Info	Analogue	False
<i>Generating Unit</i> tripped and locked out	Alarm	Normal	Info	Single	False
<i>Generating Unit</i> under frequency start	Initiate	No	Info	Single	False

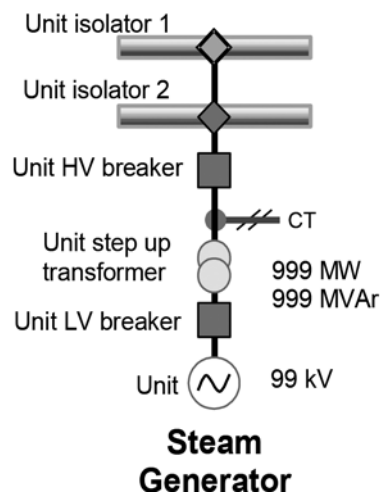
(2) **Hydro units**

Generating Unit Isolator 1	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit</i> isolator state	Open	Closed	Info	Double	False
Generating Unit Isolator 2	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit</i> isolator state	Open	Closed	Info	Double	False
Generating Unit <i>HV</i> Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
<i>Protection</i> unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating Unit breaker state	Closed	Tripped	Info	Double	False
Current Transformer	01_State	10_State	Category	Type	Control
SF6 gas critical (<i>CT</i>)	Alarm	Normal	Health	Single	False
SF6 non-critical (<i>CT</i>)	Alarm	Normal	Health	Single	False
<i>Generating Unit</i> LV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating Unit breaker state	Closed	Tripped	Info	Double	False
<i>Generating Unit</i> Step Up Transformer	01_State	10_State	Category	Type	Control
Reactive power			Info	Analogue	False
Active power			Info	Analogue	False

Isolator 3	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit</i> isolator state	Open	Closed	Info	Double	False
Isolator 4	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit</i> isolator state	Open	Closed	Info	Double	False
Generating Unit	01_State	10_State	Category	Type	Control
Frequency			Info	Analogue	False
Auto load	Active	Normal	Info	Single	True
Automatic power factor regulator	Operated	Normal	Health	Single	True
Emergency trip	Operated	Normal	Main	Single	True
<i>Generating Unit</i> start not ready	Alarm	Normal	Health	Single	False
Generating Unit to pump mode	Active	Off	Info	Single	True
Generating Unit to SCO mode	Active	Off	Info	Single	True
Pump start not ready	Alarm	Normal	Health	Single	False
Pump to generation mode	Active	Off	Info	Single	True
Pump to SCO mode	Active	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	False
SCO to generation mode	Active	Off	Info	Single	True
SCO to pump mode	Active	Normal	Info	Single	True
Sequence starting	Auto	Manual	Info	Single	False
Stator voltage	Info	Analogue	Log_only	No	
Under-frequency start	Armed	Off	Health	Single	False
<i>Generating Unit AGC</i> – high limit	High	Normal	Health	Single	False
<i>Generating Unit AGC</i> – high regulating limit	Health	Analogue	Panel	No	
<i>Generating Unit AGC</i> – low limit	Low	Normal	Health	Single	False
<i>Generating Unit AGC</i> – low regulating limit			Health	Analogue	False
<i>Generating Unit AGC</i> – raise/lower blocking	Off	Normal	Info	Single	False
<i>Generating Unit AGC</i> – ramp rate			Info	Analogue	False
<i>Generating Unit AGC</i> – set-point active power			Info	Analogue	True
Generating Unit <i>AGC</i> – status	On	Off	Info	Single	False
Generating Unit at standstill	Yes	Normal	Info	Single	True
Generating Unit voltage			Info	Analogue	False
Generating Unit guide vane			Info	Analogue	True
<i>Generating Unit</i> in generation mode	Yes	No	Info	Single	True
Generating Unit in pump mode	Yes	No	Info	Single	True

Generating Unit in SCO mode	Yes	No	Info	Single	True
Generating Unit load limiter			Info	Analogue	True
<i>Generating Unit</i> reactive power generated			Info	Analogue	False
<i>Generating Unit</i> reactive power sent out			Info	Analogue	False
<i>Generating Unit</i> active power generated			Info	Analogue	False
<i>Generating Unit</i> active power sent out			Info	Analogue	False
Generating Unit synchronising	Yes	No	Info	Single	False
<i>Generating Unit</i> turning in generation direction	Yes	No	Info	Single	False
<i>Generating Unit</i> turning in motor direction	Yes	No	Info	Single	False

(3) Steam units



Generating Unit Isolator 1	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit</i> isolator state	Open	Closed	Info	Double	False
Generating Unit Isolator 2	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
<i>Generating Unit</i> isolator state	Open	Closed	Info	Double	False
Generating Unit HV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
<i>Protection</i> unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False

Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating Unit breaker state Current Transformer	Closed 01_State	Tripped 10_State	Info Category	Double Type	False Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT) Generating Unit Step Up Transformer	Alarm 01_State	Normal 10_State	Health Category	Single Type	False Control
Reactive power			Info	Analogue	False
Active power Generating Unit LV Breaker	01_State	10_State	Info Category	Analogue Type	False Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating Unit breaker state Steam Generating Unit	Closed 01_State	Tripped 10_State	Info Category	Double Type	False Control
<i>Generating Unit AGC – high limit</i>	High	Normal	Health	Single	False
<i>Generating Unit AGC – high regulating limit</i>			Health	Analogue	False
<i>Generating Unit AGC – low limit</i>	Low	Normal	Health	Single	False
<i>Generating Unit AGC – low regulating limit</i>			Health	Analogue	False
<i>Generating Unit AGC – raise/lower blocking</i>	Off	Normal	Info	Single	False
<i>Generating Unit AGC – ramp rate</i>			Info	Analogue	False
<i>Generating Unit AGC – set-point active power</i>			Info	Analogue	True
<i>Generating Unit AGC – status</i>	On	Off	Info	Single	False
<i>Generating Unit voltage</i>			Info	Analogue	False
<i>Generating Unit islanded</i>	Alarm	No	Health	Single	False
<i>Generating Unit reactive power generated</i>			Info	Analogue	False
<i>Generating Unit reactive power sent out</i>			Info	Analogue	False
<i>Generating Unit active power generated</i>			Info	Analogue	False
<i>Generating Unit active power sent out</i>			Info	Analogue	False

Generators contributing to *Regulating Reserve* shall provide indications for *emergency* generation and maximum generation for rescheduling.

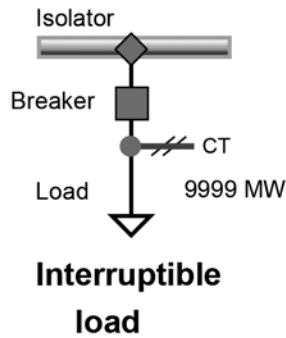
2. Distributor and end-use customer

2.1 Transmission equipment

The *Customer* shall provide operational information for both real time and recording purposes in relation to each feeder, transformer and compensation device at each *Substation* required for the full functionality of a *SVC*, as well as full control by the *System Operator*.

2.2 Interruptible load

- (1) All *Interruptible loads* shall meet the minimum requirements. The *System Operator* shall negotiate and integrate the conditions as presented in bilateral agreements and additional contracts without reducing the requirements as defined in this *Grid Code*.
- (2) The *Interruptible Load* shall install operational measurements to specification so as to provide operational information for both real time and recording purposes in relation to each controllable energy block in respect of the following minimum requirements for operation and control of a *Interruptible Load*:



Isolator	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Isolator state	Closed	Open	Info	Double	False
Breaker	01_State	10_State	Category	Type	Control
Generating Unit breaker state	Closed	Tripped	Info	Double	True
Current Transformer	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Load	01_State	10_State	Category	Type	Control
Load Reduction acknowledged	No	Yes	Info	Single	True
Load interrupt acknowledged	No	Yes	Info	Single	True
Block Load Reduction acknowledged	No	Yes	Info	Single	True
Return to service acknowledged	No	Yes	Info	Single	True
Load active power			Info	Analogue	False

- (3) The availability of the *Interruptible Load* shall be integrated into the ancillary service schedules by the market operator before the transfer to the *System Operator*.

ANNEXURE 12

Market operational schedules**1. Energy market schedules**

No	Data entity	Data description	Format	Size	Unit
1	Power Station	The official abbreviation of the <i>Power Station</i> name as defined by the <i>System Operator</i> .	Characters	5	
2	Generating Unit	The <i>Generating Unit</i> identification number.	Integer	0 - 99	
3	Hour	Contract hour.	Integer	1-24	Hour
4	Contract	The contracted generation output per <i>Generating Unit</i> .	Integer	0 - 999	MWh

No	Data entity	Data description	Format	Size	Unit
1	Power Station	The official abbreviation of the <i>Power Station</i> name as defined by the <i>System Operator</i> .	Characters	5	
2	Generating Unit	The <i>Generating Unit</i> identification number.	Integer	0 – 99	
3	Min generation	Minimum generation capability of <i>Generating Unit</i>	Integer	999	MW
4	Price 1		Real	999,99	R
5	Minus elbow 1				
6	Elbow 1		Integer	999	MW
7	Price 2		Real	999,99	R
8	Minus elbow 2				
9	Elbow 2		Integer	999	MW
10	Price 3		Real	999,99	R
11	Price 4		Real	999,99	R
12	Price 5		Real	999,99	R
13	Price 6		Real	999,99	R
14	Max generation		Integer	999	MW

2. Ancillary services market schedules

No	Data entity	Data description	Format	Size	Unit
1	Power Station	The official abbreviation of the <i>Power Station</i> name as defined by the <i>System Operator</i>	Characters	5	
2	Generating Unit	The <i>Generating Unit</i> identification number	Integer	0 – 99	
3	Hour	Contract hour	Integer	1-24	Hour (h)
4	Spinning Reserve	Spinning Reserve contract	Integer	0 – 999	MW
5	Flexibility		Boolean		'F'/'I'
6	AGC	Flag for being contracted for AGC either up or down	Boolean		'Y'/'N'
7	AGC up	Regulation contracted up	Integer	0 – 99	MW
8	AGC down	Regulation contracted down	Integer	0 – 99	MW
9	Quick Reserve	Quick Reserve contract	Integer	0 – 99	MW
10	Demand-side Quick Reserve	Reserve available from <i>Quick Reserve</i> demand-side resources	Integer	0 – 99	MW
11	Supply-side Quick Reserve	Reserve available for <i>Quick Reserve</i> from supply-side resources	Integer	0 – 99	MW

ANNEXURE 13

Post-dispatch information

- (1) The *System Operator* shall provide the following minimum operational information in near real-time and as historic *data* in relation to each *Generating Unit* at each *Power Station*:

No	Data entity	Data description	Format	Size	Unit
1	Generating Unit high limit		Real	999,99	MW
2	Generating Unit low limit		Real	999,99	MW
3	Generating Unit AGC mode	CER/BLO	Character	3	
4	Generating Unit AGC status	AUT/OFF/MAN	Character	3	
5	Generating Unit set-point		Real	99,99	MW
6	AGC pulse		Real	9,9	
7	Generating Unit sent-out		Real	999,99	MW
8	Generating Unit auxiliary		Real	999,99	MW
9	Generating Unit contract		Integer	999	MW
10	Generating Unit spinning		Integer	999	
11	AGC flag	32-bit flag on AGC settings	Integer		32 bits

- (2) If Namibia is a *control area* then the *System Operator* shall provide the following minimum operational information in near real-time in relation to the overall dispatch performance:

No	Data entity	Data description	Format	Size	Unit
1	ACE	Area Control Error	Real	999,99	MW
2		Average ACE previous hour	Real	999,99	MW
3	HZ	System frequency	Real	99,999	MW
4		Frequency distribution current hour	Real	999,99	MW
5		Frequency distribution previous hour	Real	999,99	MW
6		System total generation	Integer	99999	MW
7		Control area total actual interchange	Integer	99999	MW
8		Control area total scheduled interchange	Integer	99999	MW
9		System operating reserve	Integer	99999	MW
10		System sent-out	Integer	99999	MW
11		System Spinning Reserve	Integer	99999	MW
12		AGC regulating up	Integer	99999	MW
13		AGC regulating down	Integer	99999	MW
14		AGC regulating up assist	Integer	99999	MW
15		AGC regulating down assist	Integer	99999	MW
16		AGC regulating up emergency	Integer	99999	MW
17		AGC regulating down emergency	Integer	99999	MW
18		AGC mode	Char	TLBC /CFC	
19		AGC status	Char	ON/ OFF	
20		Area Control Error output	Real	999,99	MW
21		System Transmission Losses	Real	999,99	MW
22		South Africa tie-lines	Integer	99999	MW
23		AGC performance indicators			

ANNEXURE 14

GENERATOR PERFORMANCE DATA

1. Measurement of Availability

- (1) The Unipede/Eurelectric standard for the measurement of plant availability must be used. Availability is measured with the use of an indicator known as “energy availability factor” (EAF).
- (2) EAF represents the network point-of-view.
- (3) The “energy availability factor” has the same conceptual content as the “equivalent availability factor” used by USA operators, for example the NERC-GADS *data* bank.
- (4) Energy availability factor is defined as the ratio of the available energy generation (b) over a given time period (PH) to the reference energy generation over the same period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.
- (5) Available energy generation (b) for the purpose of calculating EAF is the energy that could have been produced under reference ambient conditions considering limitations within and beyond the control of the plant management.

$$b = Pd \times PH$$
- (6) Reference energy generation (Y) is the energy that could be produced during a given time period if the *Generating Unit* were operated continuously at reference *Generating Unit* power (PM) under reference ambient conditions throughout the period.

$$Y = PM \times PH$$
- (7) Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the *Generating Unit*.
- (8) Alternative definition: The “energy availability factor” (f), over a specified period, is the ratio of energy (b) that the available capacity (Pd) could have produced during this period to the energy (Y) that the net maximum electrical capacity (PM) could have produced during the same period.
- (9) The energy produced (b) (or capable of being produced) by the available capacity (Pd) may also be calculated as the difference between the energy (Y) (the maximum electrical capacity – PM – that could have been produced) and the unavailable energy (c) (which was not produced or not able to be produced) by the total unavailable

$$f = \frac{b}{Y} = \frac{Y - c \times 100\%}{Y}$$
- (10) Note: For the NamPower reporting systems c is calculated from a summation of unavailable MWh due to outages and restrictions (planned, unplanned, external and non-engineering) occurring throughout the period from *MW* capacity loss x duration (hr) of the loss.

2. Components of the energy availability factor (EAF) (GCR1.1)

$$EAF = UCF - OCLF$$

(1) Unplanned capability loss factor (UCLF) (GCR1.2)

The purpose of this indicator is to monitor industry progress in minimising outage time and power reductions that result from unplanned equipment failures or other conditions. This indicator reflects the effectiveness of plant programmes and practices in maintaining systems available for safe electrical generation.

(2) Other capability loss factor (OCLF) (GCR 1.3)

Other capability loss factor is an indicator to monitor outage time and power reductions due to causes beyond the control of plant management.

(3) Planned capability loss factor (PCLF) (GCR1.4)

Planned capability loss factor is defined as the ratio of the planned energy *Losses* during a given period of time to the reference energy generation expressed as a percentage.

Planned energy loss is energy that was not produced during the period because of planned shutdowns or *Load Reductions* due to causes under plant management control. Energy *Losses* are considered to be planned if they are scheduled at least four weeks in advance.

(4) Generating unit capability factor (UCF)

Note: UCF represents the *GENERATOR'S POINT OF VIEW*

The purpose of this indicator is to monitor progress in attaining high *Generating Unit* and industry energy production availability. This indicator reflects effectiveness of plant programmes and practices in maximising available electrical generation and provides an overall indication of how well plants are operated and maintained.

$$EAF = UCF - OCLF$$

3. Measurement of availability reliability

- (1) The Unipede/Eurelectric standard for the measurement of plant reliability must be used.
- (2) Reliability is measured with the use of two specific indicators, namely unplanned automatic grid separations (*UAGS*) and successful start-up rate.

4. Unplanned automatic grid separations per 7 000 operating hours (UAGS/7000h)

- (1) The purpose of this indicator is to enable monitoring of an important aspect of the reliability of service supplied to the electrical grid. It takes into account success in improving reliability by reducing the number of turbo *generator* trips. It also provides an indication of plant operation and maintenance performance.
- (2) Taking account of the number of operating hours when the turbo *generator* set is connected to the electrical grid enables assessment of required reserves. Furthermore, using a common standard for all grid separation *data* for each *Generating Unit* provides a uniform basis for comparison among units with values for the industry as a whole.

- (3) Intentional (manual) grid separations are not taken into account since operators should not be discouraged from taking action to protect equipment.
- (4) This indicator may be defined as corresponding to the number of unplanned (unintentional) automatic grid separations of internal origin that occur per 7 000 operating hours. This definition can be clarified as follows:
 - (5) “Unplanned” means that grid separation is not an anticipated part of a planned test, nor part of an operating programme designed to adjust output to demand (e.g. a controlled shutdown). Controlled shutdowns of units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.
 - (6) “Grid separation” means the opening of the *generator* breaker or *HV* yard breaker where no *generator* breaker exists. This could be an opening signal actuated by overshooting of a safety threshold, or a spurious trip. Grid separation can only occur during grid service of the units. Grid service is obtained when the start-up is successful for requested start-ups or when loads in excess of the first synchronising load are reached for “contracted” or “other start-ups” (i.e. house or block load as programmed into the automatic synchronising equipment).
 - (7) “Automatic” (unintentional) means that the grid separation is not the result of an action by the operator either on one of the switches to trigger a *Generating Unit* trip or grid separation or to simulate operation of a *Protection* system.
 - (8) Trips caused by the operator in error, e.g. opening the wrong switch leading to a trip, are excluded from the “manual” category. Controlled shutdowns of units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.
 - (9) “Operating” means that the turbo *generator* set is connected to the off-site grid (*Transmission* of generated power) even if the alternator is operating in synchronous motor mode owing to exceptional circumstances.
 - (10) “Of internal origin” means that the trip is due to an unspecified internal installation failure resulting in a loss of reliability – even if the initial event can be traced to an off-site cause. The signal that triggered grid separation must originate from one of the sensors (or *Protection* logic) for monitoring *Generating Unit* parameters (turbo *generator* set and power *Transmission*, up to and including the *generator* transformer *HV* breaker, and boiler). Grid separations actuated by *Protection* systems for the physical parameters of the grid are not included unless they were incorrectly controlled.
- (11) The selected figure of 7 000 hours represents the typical number of on-line hours for most plants operating at base load or semi-base load. The indicator thus represents an approximate value of the actual number of grid separations occurring in one year.
- (12) The following *data* are required to determine the value for this indicator -
 - (a) the number of unplanned automatic grid separations (U) with the *generator* circuit breaker (or *HV* breaker where no *generator* breaker exists) in initially closed position; and
 - (b) the number of operating hours (OPH).

- (13) All automatic trips are counted for the *UAGS* indicator, including those auto trips occurring within +30 minutes of all requested start-ups that comply with the ± 15 -minute time limit for synchronization.

$$\frac{UAGS}{7000h} = \frac{U \times 7000}{OPH}$$

- (14) Data for new units is included in the calculation of industry values beginning January 1 of the first calendar year following the start of commercial operation. However, in order to be included in the industry value, the *Generating Unit* must have at least 1 000 operating hours per year. This minimum operating period requirement reduces the effects of plants that are shut down for long periods of time and for which limited *data* may not be statistically valid.
- (15) Summarised definition of *UAGS* per 7 000 hours: This indicator tracks the average grid separation rate per 7 000 operating hours (approximately one year of operation) for units having at least 1 000 operating hours during the year. Only trips of internal origin to the installation are included and trips for the physical parameters of the grid are not included unless they were incorrectly controlled.

5. Successful Start-up Rate (GCR2.2)

- (1) The “successful start-up rate” is the ratio of the number of successful start-ups to the number of contracted start-ups over a given period of time. It measures the reliability of the service that is rendered to the *customers*.

$$SSR = \frac{\text{NumberOfSuccessfulStartUps} \times 100\%}{\text{NumberOfContractedStartUps}}$$

- (2) Start-up comprises the set of operations that enable the *Generating Unit* to be connected to the off-site power grid for the production of electrical energy according to requirements issued by the grid administrator. Connection of the *Generating Unit* to the grid (closing the line circuit breaker) is the purpose of the first start-up phase, before loading and stabilisation at the required power level. Only this initial start-up phase, the success of which results in sustained grid connection, is considered here.
- (3) The contracted start-up refers to an agreement between the grid administrator (through any medium, i.e. verbally, telephonically, etc.) and the station, following a request from the grid administrator or the station. This forms part of a grid management schedule (hereafter referred to as the ‘real’ National Control programme) for the full range of power generation resources (excluding tests). The request for a start-up in advance of the synchronising time corresponds to the technical delay due to equipment start-up times. This delay time can be reduced to almost zero in the case of start-up of peak-supply gas turbines with centralised, automatic control systems. For any given start-up contract, a precise time for grid connection and an implementation schedule are required (except for peak-load gas turbines). In the event of a sudden modification by the grid administrator of the grid connection contract time, within the start-up capabilities of the *Generating Unit*, a new contract needs to be entered into.
- (4) The following indicators are still under development:
- (a) protection management;
 - (b) ability to island;

-
- (c) excitation system management;
 - (d) reactive capabilities;
 - (e) multiple-generating unit trip risks;
 - (f) governing requirements;
 - (g) restart after station blackout capability;
 - (h) black start capability;
 - (i) intermediate load capability;
 - (j) external supply disturbance withstand capability;
 - (k) loading rates; and
 - (l) on-load tap changing for generating set-up transformers.

ANNEXURE 15

Planning schedules**Schedule 1: Ten-year demand forecast**

	Demand = Total Demand + Distribution <i>Losses</i> – Embedded Generation					
			Maximum demand		Expected minimum demand	
Year		GWh	<i>MW</i>	MVA_r	<i>MW</i>	MVA_r
Measured (year 0)						
Year 1						
Year 2						
Year 3						
Year 4						
Year 5						
Year 6						
Year 7						
Year 8						
Year 9						
Year 10						

ANNEXURE 16

INFORMATION RELATING TO DETAILS SPECIFIED

No.	Detail	Specification
1.	Commissioning	Projected or target commissioning test date
2.	Operating	Target operational or on-line date
3.	Reliability of connection requested	Number of connecting circuits e.g. one or two feeders, or firm/ <i>non-firm supply</i> required (subject to Network and Tariff Code requirements)
4.	Location map.	Upgrades: Name of existing <i>Point of Supply</i> to be upgraded and supply voltage. New connections: Provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, please specify the co-ordinates of the <i>Point of Connection</i> .
5.	Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed <i>Point of Supply</i> , and where applicable, the <i>Transmission</i> line route from the facility boundary to the <i>Point of Supply</i> , clearly marked.
6.	Electrical single-line diagram	Provide an electrical single-line diagram of the <i>customer</i> intake <i>Substation</i> .

ANNEXURE 17

MEASUREMENT EQUIPMENT ACCURACY CLASSES

Measurement equipment	Accuracy class
Current transformer (CT)	0,2%
Voltage transformer (VT)	0,2%
Transducer	0,2%
Analogue to digital conversion, i.e. RTU	0,01%

ANNEXURE 18

DAILY 24 HOURS DAY-AHEAD ENERGY SCHEDULE

File	Description	Trigger event	Frequency
Dispatch schedule	The combined 24-hour <i>day-ahead</i> energy and <i>ancillary services</i> schedules. Hourly <i>day-ahead</i> contracts for different market categories that identify the <i>Generating Unit</i> with the next 24 hourly values for it.	Generation dispatch schedule	Daily
Daily price curve	Daily price curve with incremental prices and corresponding volumes.	Generation dispatch schedule	Daily

ANNEXURE 19

File	Description	Trigger Event	Frequency
AGC pulses	The total pulses sent to a Generating Unit by the AGC system to move the set point up or down	Ongoing, file created at end of hour	Hourly
NERC	A list of the total NERC "A1" and "A2" criteria violations in the system over an hour	Ongoing, file appended at end of hour	Daily
System near real-time data	Historic near real-time system data files on readings as required for post-dispatch	Communication failure	To be agreed
Generating Unit near real-time data	Historic near real-time Generating Unit data files on readings as required for post-dispatch	Communication failure	To be agreed

ANNEXURE 20

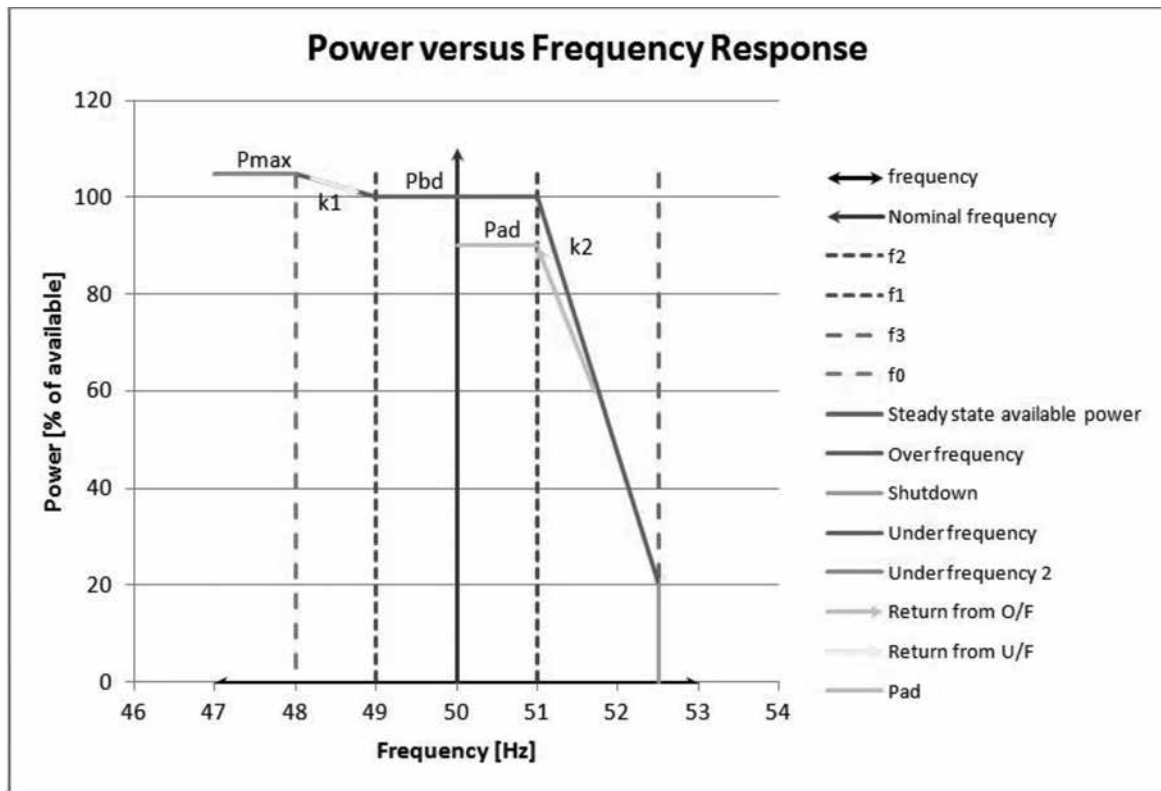
Distributor :				
Date:				
Substation:				
Fed from Transmission Substation (directly or indirectly):				
	Activating frequency		Timer setting	
	Required	As tested	Required	As tested
Stage 1				
Stage 2				
Stage 3				
Stage 4				
	Feeders selected (Required)		Feeders selected (As tested)	
Stage 1				
Stage 2				
Stage 3				
Stage 4				

ANNEXURE 21

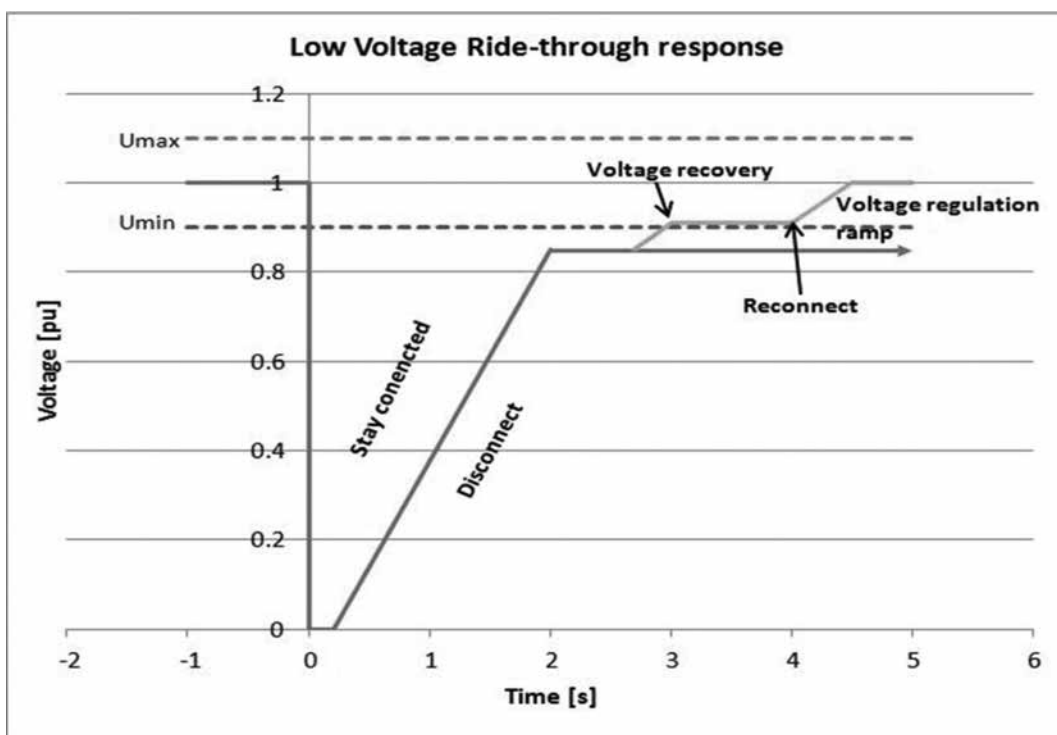
Indicator	Month	Year to date	12 MMI	Unit
System Minutes lost				minutes
No. of Interruptions				
No. of statutory voltage transgressions				
Mandatory under-frequency load shedding				
Customer voluntary load shedding				
Transmission system Losses				%

ANNEXURE 22

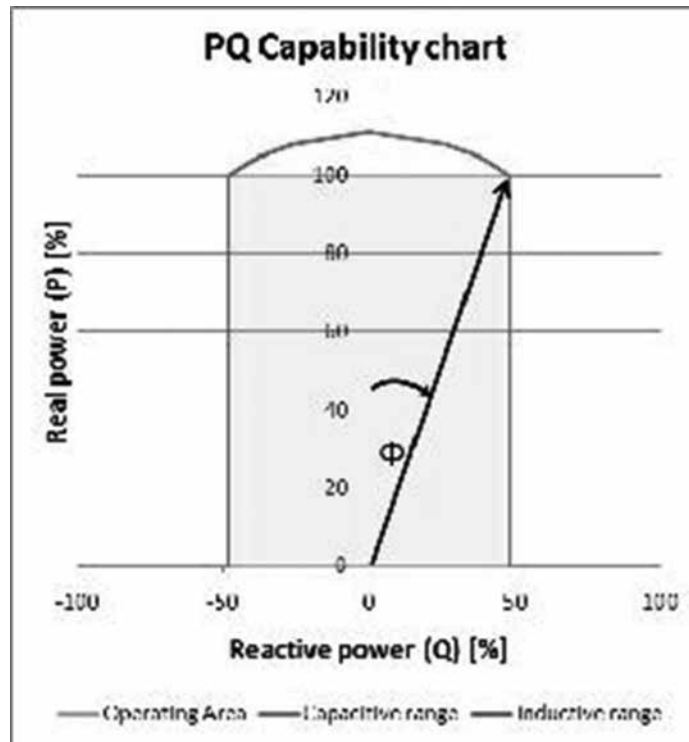
The values of f_0 , f_1 , f_2 , f_3 , k_1 , k_2 , and k_3 must be settable for the specific network location and applicable conditions. The range of values for k_1 and k_2 are automatically determined by the range of values given above for f_0 , f_1 , f_2 , and f_3 .



ANNEXURE 23



ANNEXURE 24



ANNEXURE 25

Total Harmonic planning levels

Harmonic order	Harmonic voltage %	
	MV (up to 33kV)	HV/EHV (above 33kV)
2	1.6	1.5
3	4	2
4	1	1
5	5	2
6	0.5	0.5
7	4	2
8	0.4	0.4
9	1.5	1.5
10	0.4	0.4
11	3	1.5
12	0.2	0.2
13	2.5	1.5
14	0.2	0.2
15	0.3	0.3
16	0.2	0.2
17	1.6	1
18	0.2	0.2
19	1.2	1
20	0.2	0.2
21	0.2	0.2
22	0.2	0.2
23	1.2	0.7
24	0.2	0.2
25	1.2	0.7
>25	$0.2 + 0.5*25/h$	$0.2 + 0.5*25/h$
Inter-harmonics	0.2	0.2
THD	<6.5	<3