Interim Grid Code for Sierra Leone Electricity Market

Version 1.00

Sierra Leone Electricity and Water Regulatory Commission

March 2021

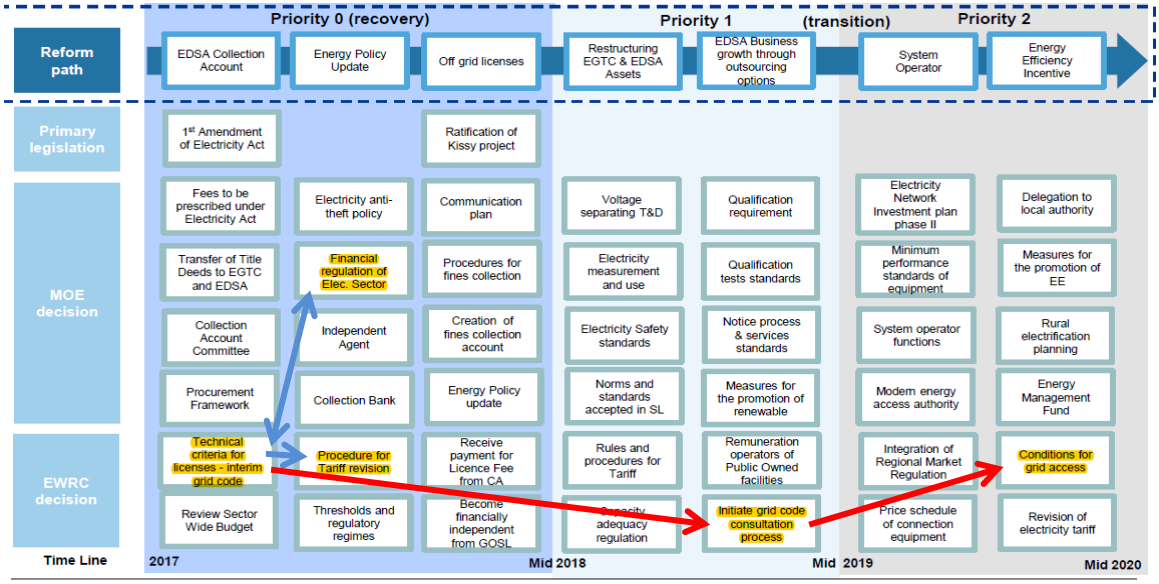
Foreword

Regulatory Context as Per Roadmap for Reform of Electricity Sector

The National Electricity Act of 2011 and The Sierra Leone Electricity and Water Regulatory Commission Act of 2011 provide the basis for establishment of an ongoing programme of reform in the Sierra Leone electricity industry. A road map for implementing the electricity industry reform is being developed by Adam Smith International and the 8 September 2017 version provided guidance in preparing this Draft 0.0 of the Interim Grid Code. This Interim Grid Code is one of the key planks in implementing the initial (recovery) stage of the reform. It is subject to consultation during the transition period, as a priority 1 task, and will evolve to a final grid code and set the conditions for grid access as a priority 2 task during the transition phase.

It sets the technical criteria for licences under Electricity and Water Licensing Rules and sits alongside other regulations and rules such as the Electricity (Quality of Supply) Regulations, and the Electricity Distribution and Supply (Consumer Service) Regulations. It amplifies the quality of supply regulations by providing more detail on how certain Transmission Network Operator (TNO) and System Operator (SO) performance measures are to be measured and reported.

Draft Short Term Roadmap for reform of the Electricity Sector



Adam Smith International

Relationship to Financial Regulations

The Interim Grid Code and the Financial Regulations (another priority 0 task in the roadmap) inter relate in that security constrained economic dispatch, under the Interim Grid Code (Chapter VI), needs an input of an economic merit order for generation dispatch (from the Financial Regulations) and metered quantities (provided under the metering sections of the Interim Grid Code) are inputs to any financial settlement arrangements under the Financial Regulations.

Relationship to Tariff Regulations

The Interim Grid Code also inter relates to the Procedure for Tariff revision (another priority 0 task in the roadmap) in that tariff revision will need to consider what transmission investment is required and how to recover those costs. The Interim Grid Code provides a process for ensuring transmission investment (Chapter V) is efficient and forms an input to any changes in transmission tariffs.

Establishes Rules, Responsibilities and Relationships for Safe and Efficient Operation

The Interim Grid Code aims to ensure safe and efficient operation for all parties connected to the Grid. It establishes the basic rules, requirements and procedures that govern connection, operation, maintenance and development of the high voltage transmission network in Sierra Leone. It also discusses various elements of the connection to and operation of the distribution network. In further includes the integration of renewable energy plants onto the transmission and distribution networks. The Interim Grid Code identifies and defines the responsibilities of two key independent functional entities in the Sierra Leone industry, namely the Transmission Network Operator(s) and the System Operator. These functional entities, and all parties connected to the transmission network, or generators operating within the Sierra Leone Electricity Network must comply with the provisions of the Interim Grid Code.

Development Approach Taken

Interim Grid Code Provides Development Path for Industry

The approach taken in developing this interim Grid Code is to provide a clear development path for the electricity industry by:

- Outlining the level of security of operation that future investors will want to see as a condition of connecting to the grid;
- Providing detail of the procedures and processes that the SO and TNO(s) will need to develop to achieve that level of security of operation;
- Providing a pathway to develop towards that level of security of operation; and
- Allowing flexibility in how commercial arrangements might develop.

Future Investors Want to Understand Risks of Connection and Confidence of Future Direction

Any new party planning an investment that requires connecting to the Sierra Leone electricity grid will want to understand what technical and commercial risks arise from the connection and the rules (Grid Code) that are required for that connection. Examples of possible investors might include Independent Power Producers (IPPs) and West African Power Pool (WAPP) connection providers. By providing a high level of detail on how the grid will operate, and providing a broad scope (covering right from investment planning and cost allocation through to real time operation and even post operation metering, with a link to settlement) this Interim Grid Code will support future investment in the grid. Investors just need a clear signal of where the regulatory arrangements are going, and confidence it will reach that state of development, even if it is not currently in that state.

System Operator and Transmission Network Operators Need Detail to Help Develop Systems and Processes

The duties, obligations of each party, and the System Operator (SO) and Transmission Network Operator(s) (TNO(s)) are spelt out in great detail. This includes detail of the processes and system required to support those duties and obligations. It is recognised

that the current players may not have the implied level of systems or personnel capacity. But providing detail of the requirements helps them develop that capacity by providing a guided pathway forward.

Exemption Process Provides a Development Path

As well as providing an end goal of the desired future level of development the Interim Grid Code provides a pathway for achieving that end goal by allowing an (EWRC controlled) exemption process. This allows EWRC to control the timing and process for moving towards the end goal, of a fully functional grid code by:

- Requiring the key players, e.g. SO and TNO(s) to:
    - Identify where they cannot currently completely fulfil the requirements;
    - Identifying how this limitation impacts on others;
    - Propose how they will meet the functional requirements in the interim;
    - Propose a timetable and process for moving towards completely fulfilling the requirements;
- Allowing the EWRC to control the development direction and timing by giving it control on:
    - How it consults affected parties on any proposed exemptions;
    - What exemptions to approve;
    - What time constraints to impose on any approval;
    - Any other conditions it may wish to impose on any exemptions.

Flexibility in Commercial Arrangements Allowed For

The Interim Grid Code provides for flexibility in the commercial arrangements supporting the electricity industry development by:

- Allowing for multiple commercial arrangements to operate in parallel, e.g. Different Power Purchase Agreements (PPAs), a real time market, a day ahead market, different options for price discovery and price caps; and
- Allowing for evolution of commercial arrangements over time.

The nature of the commercial arrangements, with generators, WAPP pool operation, and end consumer sales seems to be still evolving at this point. The Interim Grid Code provides for a future state where several sophisticated arrangements could exist in parallel, e.g.

- Some standardised PPA's;
- Some customised PPA's;
- A day ahead market;
- A real time market; and
- Possible price caps in contracts or markets under some circumstances.

It is unlikely that all these arrangements will exist initially. So the Interim Grid Code allows for this by:

- Not requiring any of them to operate (it just needs some way of an economic merit order of generation to be derived); and
- Being flexible about who is designated to fulfil different functions, e.g. EDSA could be designated (by EWRC) as fulfilling the Market Operator (MO), Distribution Company (DC), Trader and even seller functions initially. With these functions separated out over time if desired.

Identifying Possible Further EWRC Work to Support Road Map Development

This Grid Code also identifies other areas where EWRC may (if it hasn't already done so) need to define procedures or rules to fulfil its obligation under the Sierra Leone Electricity and Water Regulatory Commission Act of 2011, such as:

- Market Rules and Standard PPAs (for power market bidding, pricing, settlement etc.) - Part of financial regulations; and
- Master Planning Rules and Least Cost Expansion Rules (for co-ordinating generation and transmission investment) - Part of tariff revision procedures.

This Grid Code defines how such rules, agreements, and procedures integrate with this Grid Code.

How Development Approach Implemented - Functional Approach Accommodates Future

The Interim Grid Code was prepared using a functional, rather than an organisational, approach so that it will remain robust and require minimal changes as the electricity industry evolves and the reforms proceed. Some of the known future evolutions include:

- The connection to the West African Power Pool,
- Increasing levels of non-dispatchable renewable generation; and
- The functional separation of the Electricity Generation and Transmission Company (EGTC) into separate Generation, Transmission and System Operator/Market Operator functions.

These have been allowed for as follows.

Connection to the West African Power Pool (WAPP)

Connection to the WAPP has been allowed for by:

- Allowing for multiple transmission network operators; and
- Allowing for power pool transactions in planning, scheduling, dispatch and outage planning.

Allowance for multiple transmission network operators

It is unclear at this point who will build, own, operate and connect to the interconnecting transmission line. It is possible this may not be the transmission arm of EGTC. Therefore we have allowed for multiple transmission network operators, with common duties, co-ordinated by the System Operator, in the Interim Grid Code.

Allowance for power pool transaction planning, scheduling, dispatch, outage planning

Although power pool transactions will primarily be covered in the separate power pool, and market rules (not part of this Grid Code) the Interim Grid Code allows for such transactions in the transmission network operators investment planning (Chapter V) and system operators security assessment process for the security constrained economic scheduling and dispatch process (Chapter VI), demand forecasting (Chapter VII) and outage planning (Chapter VIII).

Allowance for Increasing Levels of Non-dispatchable Renewable Generation

The roadmap also makes it clear that increasing levels of non-dispatchable renewable generation are expected at both grid connected level and embedded within the distribution network. This raises challenges for maintaining grid security because of the uncontrolled and variable nature of output from the non-dispatchable renewable generation. The chapter on the Integration of Variable Renewable Power Plants looks towards defining

how these non-dispatchable plants will connect to both the grid connected level and embedded within the distribution network. It also delves into the issues relating to the accompanying grid stability and security due to the variable nature of their supply. As a result, the system operator needs to be able to balance demand and generation in real time to maintain grid security, so the SO needs some visibility of the *likely* output and some way of managing the variation from likely to actual output.
The Interim Grid Code makes specific allowance for this by:

- Defining non-dispatchable generators in the definitions (Chapter I);
- Getting visibility of *likely* output:
    - Making the distribution companies (DCs) responsible for accounting for likely output from non-dispatchable renewable generation within their network during the demand forecasting process (Chapter VIII);
    - Making grid connected non-dispatchable generator, or embedded generators above the threshold (2MW), responsible for forecasting their likely output during the generator offering process (Chapter VI);
    - Allowing EWRC to set a wider dispatch compliance tolerance band for non-dispatchable renewable generator, to recognise the difficulties in accurately forecasting their output (Chapter VI); and
- Managing the variation from expected output by:
    - Requiring the System Operator (SO) to procure and dispatch sufficient reserves (spinning reserve, regulation and fast start reserve) to cover variation from expected output (Chapter VI).

It is noted that the Interim Grid Code does not deal with the commercial aspects of non-dispatchable generation. For example, the value of that generation to the grid, compared to dispatchable generation or how the costs of extra procured ancillary services should be allocated. That is best dealt with in the PPA's or market rules.

Separation of Different EGTC and EDSA Functions:
Specify Duties Now, Regulate Who Performs Them

The Interim Grid Code allows for the future separation of EGTC into separate generation, transmission and system operator / market operator entities by specifying in detail the duties of each entity now. The timing of that separation can be accommodated by specifying, in separate regulation by Sierra Leone Electricity and Water Regulatory Commission (EWRC), who performs each function. For example EWRC could regulate (under article 66 of the 2011 EWRC Act) that initially EGTC is to perform all these functions, but could later specify the separated entity for each function.

Similarly the Interim Grid Code allows for evolution of commercial arrangements between consumers and generators, and possible future separation of EDSA functions, by specifying a Trader(s) function to purchase electricity from generators and sell to other distribution companies (DCs) and (should they exist in the future) direct connected consumers (DCCs). It is recognised that this function will initially be part of the Electricity Distribution and Supply Authority, and it can be deemed to be the initial Trader. But it is good to allow future flexibility in how this role might be provided in future.

Building Capacity and Evolving Standards

Another challenge facing the Sierra Leone electricity sector is the current lack of systems and personnel capacity in power system operation. The Interim Grid Code addresses this by:

- Building capacity by specifying detailed procedures and system requirements; and
- Accommodating current capabilities via the exemption process.

Detailed Procedures and Processes Build Capacity

As well as specifying requirements for safe power system operation, the Interim Grid Code specifies detailed procedures and processes each party will need to meet the requirements. Sufficient detail is provided on each process to allow each entity to develop its own systems and processes to meet this Grid Code and ensure smooth operation of the power system. Some flexibility is provided for the System Operator to specify further detail around timings and additional procedures.

Exemptions Accommodate Learning

It is likely that it will take some time for everybody involved to develop the capacity (systems, procedures and people) to completely fulfil their obligations under this Grid Code. This needs to be recognised but also incentives provided to improve and continually develop. This has been provided for with a process for the EWRC to issue time bound exemptions (Chapter XVI), or for longer term issues dispensations, to this Interim Grid Code. By allowing EWRC to attach conditions, including time constraints, to such exemptions and dispensations the Interim Grid Code allows EWRC to retain control of the overall development time table and direction. The implementation provisions (Chapter XVIII) further enhance this capacity development process by requiring the key players (TNO(s) and SO) to develop detailed implementation plans for the EWRC to review and approve, prior to go live.

Chapter Outlines

The Interim Grid Code is organised into 18 chapters, these are:
Chapter I – General Provisions
Chapter II – Governance
Chapter III – Power System Performance Standards
Chapter IV – Connection to the Transmission Network
Chapter V – Network Planning
Chapter VI – Power System Operation
Chapter VII – Demand Forecasting
Chapter VIII – Outage Planning Process
Chapter IX – Performance Indicators
Chapter X – Transmission Metering
Chapter XI – Connection to the Distribution Network
Chapter XII – Distribution Network Operations
Chapter XIII – Distribution Network Information Exchange
Chapter XIV – Distribution Metering
Chapter XV – Integration of Renewable Energy into the Transmission and Distribution Networks
Chapter XVI – Exemption Procedures
Chapter XVII – Dispute Resolution
Chapter XVIII – Implementation

Chapter I lays out what is covered in the Interim Grid Code, establishes the guiding principles and purpose of the Interim Grid Code, defines the scope of who is covered by the Interim Grid Code, the hierarchy of the Interim Grid Code relative to other codes and rules, and defines key terms used in the Interim Grid Code. This includes defining boundaries between any WAPP pool rules and codes and this Interim Grid Code.

Chapter II establishes the governance procedures for changes to the Interim Grid Code. It defines the roles of industry participants and the Electricity and Water Regulatory

Commission (EWRC) in making changes to the Interim Grid Code (as per article 66 of The Sierra Leone Electricity and Water Regulatory Commission Act of 2011).

Chapter III lays out the power quality performance standards that the System Operator and Transmission Network Operator are to aim for in operating the power system. This links to Chapter IX, which defines how such performance standards are to be measured. These dovetail with the Electricity (Quality of Supply) Regulations by separating out the reporting requirements of the TNO and SO (which are combined in the regulations) and specifying in more detail how the reporting requirements provided for in the regulations are to be measured and reported. It also provides for slightly more granular reporting than provided for in the regulations.

Chapter IV defines the process for connection to the transmission network(s) and the technical standards that connected parties must comply with.

Chapter V lays out the process and procedures the TNO(s) must go through in developing their annual transmission expansion plan. Noting that a single common standard applies regardless of who owns the transmission network (to allow for a separate owner for the WAPP interconnection).

Chapter VI details the principles, procedures and processes for secure power system operation. It defines the roles and responsibilities in system operation, the ancillary service procurement procedures, the scheduling and dispatch process, fault resolution procedures and safety co-ordination procedures. It includes specific provision for managing the impact of larger non-dispatchable renewable generation.

Chapter VII details the roles and responsibilities of all parties in producing the demand forecast data used in operational planning right from 5 years ahead to hourly operation. It includes specific provision for distributors to account for the impact of smaller embedded non-dispatchable generators on their demand forecasting.

Chapter VIII lays out the roles and responsibilities of all parties in planning and co-ordinating generation and transmission outages (including interconnection to the WAPP) to ensure secure operation of the power system.

Chapter IX defines how the performance indicators laid out in chapter 3 are to be measured.

Chapter X lays out metering requirements and procedures for measurement of transmission network injection and off take. It does not cover distribution level metering off take, and allows for PPAs to specify higher or more detailed standards.

Chapter XI specify the fundamental procedures and rules for connecting to the distribution network. It seeks to guarantee the non-discriminatory treatment of distribution network users and to state the technical requirements for the safe and reliable operation of the distribution network.

Chapter XII seeks to set out the responsibilities and roles of the participants as far as the operation of the Distribution System is concerned and more specifically issues related to economic operation, reliability and security of the Distribution System; operational authority, communication and contingency planning of the Distribution System; the management of power quality; the operation of the Distribution System under normal and

abnormal conditions; field operation, maintenance and maintenance coordination / outage planning within the Distribution System and the safety of personnel and the public.

Chapter XIII seeks to define the reciprocal obligations of participants with regard to the provision and exchange of planning, operational and maintenance information on the Distribution Network.

Chapter XIV aims to ensure compliance with minimum requirements for tariff metering and energy trading metering installations; to define responsibilities for metering installations and to ensure that appropriate procedures are followed by the distributor of electricity (distribution licencee) and its metering service provider regarding the maintenance, validation, collection, processing and verification of metering data.

Chapter XV deals with the integration of renewable energy into the Transmission and Distribution Network and it establishes the minimum technical and design grid connection requirements for Variable Renewable Power Plants (VRPPs) connected to or seeking connection to the electricity transmission and distribution networks in Sierra Leone.

Chapter XVI recognises that not all parties will be able to fully comply with the full requirements for the Interim Grid Code on day one and establishes a procedure for application for exemptions from the provisions of the Interim Grid Code.

Chapter XVII establishes the principles and processes for dealing with disputes arising under the Interim Grid Code or possible breaches of the Interim Grid Code.

Chapter XVIII lays out the roles and responsibilities in implementing the Interim Grid Code and includes transition provisions to assist parties in meeting their obligations under the Interim Grid Code. It includes requirements for the TNO(s) and SO to develop detailed implementation plans for EWRC to review and approve.

ACKNOWLEDGEMENTS

This Electricity Grid Code, although uniquely Sierra Leonean, was initially drafted by the consultants, AARC and Neil Walbran, under the Regulatory Strengthening and Tariff Determination project which formed a core part of the Millennium Challenge Corporation's Threshold Programme for Sierra Leone. The Code has also drawn on the following regionally and internationally available grid codes, sub-codes and documents, where applicable:

a. The South Africa Distribution Code
b. The Ghana Renewable Energy Sub-Codes for Transmission and Distribution Networks
c. The United Kingdom Grid Code
d. The Nigeria Grid Code

The detailed review of the initial draft was done by the Grid Code Review Committee (GCRC), which comprised of the following members:

Ing. L. J. Tani Pratt	EWRC	GCRC Chairman
Ing. Kelcise Vidal Sesay	EWRC	GCRC Editor and Coordinator
Dr. Emmanuel Mannah	EWRC	
Ing. Dr. David Kamara	EGTC	
Ing. Aleksandar Nikolic	EDSA	
Ing. Suresh Kumar Musala	EDSA	
Ing. Edward D. Parkinson	EDSA	
Ing. Ahmed J. S. Fomba	EGTC	
Ing. Dr. David Caulker	MoE	
Ing. Sidi B. Saccoh (Late)	SLIE	
Ing. Francis Nyama	EDSA	
Ing. Chernor Jalloh	EDSA	
Ing. George Seiya	EDSA	
Ing. Theophilus Amara	EDSA	
Ing. Benjamin Bash Kamara	EGTC	
Ing. Paul Saffa	Transco CLSG	
Ing. Dr. Patrick Tarawalli	MoE	
Ing. John Kabia	EGTC	
Ing. Sinneh Kamara	EGTC	
Ing. Bibhuti Bhushan	G. Shankerdas	
Ing. Sylvain Ndour	Bollore	

Alfred Bangura	PPP Unit
Mohamed P. Bangura	MoJ
Prince Williams	MoJ
Mohamed S. Samura	EGTC
Yankay Sawanneh	Karpower Ship
Dogucan Bayrackar	Karpower Ship
Ruaan du Toit	Karpower Ship
Machiel Coetzie	Karpower Ship
Yashgadda Naveeh	Sunbird BioEnergy
Natarougan Ramesh	Sunbird BioEnergy
Mohamed Fofanah	SL Standards Bureau
Brima Bah	EWRC
Ngozi Obi Sesay	EWRC
Ing. Cyril Boima	EWRC
Ing. Bockarie M. Musa	EWRC
Komba Ngongou	EWRC
Ann-Marie Turay	EWRC
Fatmata Barrie	MCCU
Daniel Carpenter	MoE
Shebora Kamara	MoE
Moses Gbateh	MoE
Emmanuel Osei	LEOCEM
Mathias Abu-Mattia	EDSA
Mohamed B. Kamara	EGTC
Ing. Abu Bakarr S. Bah	EGTC
Ing. Foday Conteh	EGTC
Irvinia G. Betts	SLCCIA

TABLE OF CONTENTS

List of Figures

List of Tables

GENERAL PROVISIONS AND GOVERNANCE

Chapter I. General Provisions

Interpretation

Hereinafter, the following words and expressions shall, unless the subject matter or context otherwise requires or is inconsistent therewith, bear the following meanings:

1) **Active Power:** Multiplication of voltage (U), the phase component of AC current (I) and the cosine of the angle between U and I. The active power is measured in Watt (W), and its multiples kW, MW and GW, and symbolized by letter “P".

2) **Active Power Curtailment Set-point:** The limit set by the SO, or their agent for the amount of active power that the VRPP is permitted to generate. This instruction may be issued manually or automatically via a telecontrol facility. The manner of applying the limitation shall be agreed between the parties.

3) **Annual List:** An annual list of generation and transmission network development projects developed by EWRC.

4) **Apparatus:** Any equipment associated with the generation, transmission, distribution or consumption of electricity.

5) **Asset Owner:** A person who owns the whole or part of the transmission system or any facility connected to the transmission system.

6) **Automatic Generation Control (AGC):** The function of AGC is to change the active power output of generating units for the purpose of frequency control and economic dispatch process through automatic control system. AGC is sometimes referred to as set point control.

7) **Automatic Voltage Regulator (AVR):** A continuously acting automatic closed loop control system acting on the excitation system so as to maintain a Generation Unit’s terminal voltage at a desired set point.

8) **Available Active Power:** The amount of active power (MW), measured at the POC, that the VRPP could produce based on plant availability as well as current renewable primary energy conditions (e.g. wind speed, solar radiation).

9) **Available Capacity:** The maximum possible amount of electricity, in MWs, a generating unit is capable of delivering to the Transmission Network for one hour.

10) **Availability:** Power capacity of the generator, expressed in Watts, ready for generating within specified time (hour).

11) **Availability certificate:** Written paper which certifies that connection has been accepted and ready to supply or receive electricity, issued by authorized persons managing operation of transmission network to power generation agencies, distributor or the external power system agencies.

12) **Backup metering system:** A set of one or more metering systems assigned with the following tasks:

    a) A substitute for the main metering system, used as an evidence for calculating the traded energy when the main metering system operates inaccurately or fails;

b) Monitoring and checking the metered result of the main metering system when the main metering system operates normally.

13) **Black start capability:** The ability of a power plant to start a generating unit from shutdown and synchronize without an external electrical power supply within a specified time.

14) **Bona fide physical reason:** Relates to unplanned changes in equipment availability. It includes automatic plant operation in response to a fault situation, or action where personal or plant safety is in danger, or action where failing to carry out an action would breach legal or safety requirements, or changes in fuel availability that could not have been reasonably anticipated.

15) **Capability Curve:** A curve developed for generators showing the limits of reactive and active power that a generator can produce without overheating or becoming unstable.

16) **Capacity margin**: The difference between the total forecast peak demand and the total forecast available generation capacity, taking into account planned and unplanned generator outages, and variability of non-dispatchable renewable generation.

17) **Collapse of the power system:** A situation, in which, all elements of the power system have lost electricity.

18) **Cold start reserve:** An ancillary service provided for the purposes of ensuring adequate energy margin in the mixed hydro thermal generating system.

19) **Connection Agreement:** It is an agreement between the TNO and a Grid Participant that seeks connection of its facilities to the TNO's network and sets out the rights, obligations and liabilities of both parties.

20) **Connection charge:** A charge recouped from the customer for the cost of providing new or additional capacity (irrespective of whether new investment is required or not). This is recovered in addition to the tariff charges as an up-front payment (connection fee) or as a monthly charge where the distributor finances the connection.

21) **Connection fee:** Minimum upfront contribution

22) **Connection point:** The point of physical linkage to or with the TNO's network for the purpose of enabling the flow of electricity as the boundary between the transmission network and a facility or other equipment owned by the transmission network user as defined in Article 43.

23) **Connection Site:** Site at which the Plant and Apparatus of the user at the user's side of the Connection point is to be installed including the land, spaces, roads and any surfaces.

24) **Consumer:** Party who consumes electricity primarily for their own benefit.

25) **Continuous Operation Range:** Network frequency or voltage operating range, outside normal range of operation, within which no generating unit is allowed to disconnect and where power output restrictions may exist.

26) **Current transformer (CT):** An instrument transformer in which the secondary current, in normal conditions of use, is substantially proportional to the primary current

and differs in phase from it by an angle which is approximately zero for an appropriate direction of the connections.

27) **Curtailed Active Power:** The amount of Active Power that the VRPP is permitted to generate by the SO, or their agent subject to network or system constrains.

28) **Customer using power transmission system:** Individual, institution who have a licence for operation in power generation, selling bulk electricity, or electricity distribution and who trade electricity through the power transmission system.

29) **Data collecting, processing and archiving system:** Set of the hardware devices, information transmission channel and the software programs which have the functions of collecting, transmitting, processing and archiving the metered data for serving the transactions and payment in the power market.

30) **Daytime peak:** Highest power consumption in the power system during the time from 8 h to 17 h in a day.

31) Deep connection costs: Marginal costs of reinforcing the TNOs assets required solely as a result of new connection.

32) **Dependability index**: The probability that a protection system, and all associated equipment, will successfully detect and clear a genuine fault. It is calculated taking into account the sensitivity, discrimination and reliability of the protection system and all associated equipment.

33) **Directly Connected Consumer (DCC):** Consumer whose plant is directly connected to the transmission network.

34) **Dispatch:** The process by which the SO controls the power system as a whole in real time to ensure secure and economic operation.

35) **Dispatch instruction:** An instruction issued by the SO for the purposes of achieving dispatch.

36) **Dispatch Instruction Management (DIM) system:** System used by the SO for issuance of all real time dispatch instructions.

37) **Distribution Company (DC):** A licensee or its appointed representative that constructs, operates and maintains the distribution network,

38) **Distribution Control System (DCS):** Computerize control system interconnected by local area network with target to minimise impact of local fault in one of computers.

39) **Distribution Management System (DMS):** Package of software to control distribution network.

40) **Distribution Network:** The network owned and operated by a Distribution Company.

41) **Distribution System (DS):** That portion of the network which is normally operated at voltages below 66 kV, excluding assets owned by generators, and as defined in the Electricity and Water Licencing Rules.

42) **Disturbance:** An unplanned event that produces an abnormal system condition or any occurrence that adversely affects normal power flow in a system.

43) **Droop:** A percentage of the frequency change required for a VRPP to move from no-load to rated power or from rated power to no-load.

44) **Echo:** In relevance to park control system, it is the signal that is sent from a VRPP to the communication system of the network operator.
45) **Economic Cost:** Total cost of the electricity related investment to both the Distribution Company and the customer(s).
46) **Economic evaluation:** The project benefits and return, including both the Distribution Company's and the affected customer's costs related to electricity infrastructure.
47) **Electrical single line diagram:** Single line electric diagram showing connection of equipment in the power system.
48) **Electrical Equipment Norm:** A document issued by the SO from time to time defining protection system requirements.
49) **Electricity and Water Regulatory Commission (EWRC or the Commission):** The legal entity established in terms of the SLEWRC Act No. 13 of 2011, as amended.
50) **Embedded generator:** A legal entity that operates one or more unit(s) that is connected to the Distribution System. Alternatively a legal entity that desires to connect one or more unit(s) to the Distribution System.
51) **Emergency:** Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of generation supply or transmission facilities that could adversely affect the reliability and safety of the electric system.
52) **Emergency load shedding:** Any process for reducing load when required to do so to maintain system security. It includes, but is not limited to, under frequency automatic load shedding.
53) **Emergency regime of the power system:** Situation in which the entire or a part of the power system is threaten to stop operation because safety, reliability is not ensured or synchronization is lost.
54) **End-use customer:** Users of electricity connected to the Distribution System.
55) **Energy charges**: Charges designed to recover the costs of electrical energy.
56) **Energy Management System (EMS):** A package of software which is used in association with SCADA system for real time control of power system equipped at the dispatching centers.
57) **Energy margin:** Margin of energy supply over energy demand over the period in question, taking into account variability of hydro inflows, availability of non-hydro generators, any other fuel supply restrictions, and demand forecast errors.
58) **Equipment automatically separating generator unit from the transmission network:** Automatic equipment which is responsible for receiving and sending signals to separate selected generating units from operation in specified situations.
59) **Evening peak:** Highest power consumption in the power system during the time from 18 h to 21 h in a day.
60) **Excluded services:** Services requested by customers that are excluded from the regulated activities and funded directly by the customer requesting the service.
61) **External connection partner:** Individual, or institution having its own power systems, power plant connected to the transmission network in order to buy electricity from or sell electricity.

62) **External power system:** Power system outside of, but interconnected to the transmission network of the TNO.

63) **Extra High Voltage (EHV):** A voltage level exceeding 225 kV.

64) **Fault (in a power system):** Abnormal incident on the power system or related to the power system leading to or may lead to operation situation that is not complied with specified standards or causing damage to people and property.

65) **Financial evaluation:** The project benefits and return over the life cycle of the project

66) **Firm supply:** A Distribution supply that can withstand any single (n-1) contingency within the Distribution network, e.g. the customer supply shall not be dependent on any single component.

67) **Flicker:** A fast fluctuation in voltage leading to quick intermittent coming on, of an appliance and gives the impression of unstable visual sensation induced by a light stimulus with luminance or spectral distribution that fluctuates with light.

68) **Flicker Severity (Short term) P_{st}:** Measure of the visual severity of flicker derived from the time series output of a flicker meter over a ten-minute period. It can be measured by the flicker meter in accordance with IEC868.

69) **Flicker Severity (Long term) P_{lt}:** Value derived from 12 successive measurements of Flicker Severity (Short Term) over a two-hour period calculated as formula below:

$$P_{lt} = \sqrt[3]{\frac{1}{12} * \sum_{j=1}^{12} P_{stj}^{3}}$$

70) **Forced outages:** 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/emergency conditions or human error.

71) **Frequency control:** The control of active power with a view to stabilising frequency of the grid.

72) **Frequency regulation:** The automatic adjustment of active power output by a generation unit, initiated by fast acting frequency controller action in response to continuous minor fluctuations of frequency on the power system.

73) **Generating station:** Group of two or more generating units that are physically connected to the transmission network or to a distribution network and which are combined and bid at a single connection point.

74) **Generating unit:** An individual machine that generates electricity.

75) **Generator:** Person or institution that owns one or more generating units connected to the transmission network or to a local network.

76) **Grid Advisory Committee (GAC):** A committee appointed by EWRC, in accordance with the procedures in Article 9, to advise EWRC on proposed changes to this Interim Grid Code.

77) **Ground Fault Factor:** Ratio of the voltage of the unfaulted phase at the point of ground fault to the phase voltage at that point before ground fault (apply for one-phase short circuit or 2-phase-grounding short circuit).

78) **Harmonics:** A sinusoidal wave having a frequency that is an integral multiple of a fundamental frequency.

79) **Heat consumption rate curve:** Curve expressing heat amount consumed by turbine-generator unit in one hour at different generated output levels.

80) **Heat rate:** Amount of heat used by the turbine-generator unit for producing one unit of electricity (kcal/kWh).

81) **High Voltage (HV):** Voltage level from 66 kV up to and including 225 kV

82) **IEC standard:** Set of standards of the electricity technique issued by the International Electrotechnical Commission.

83) **Individual Harmonic Distortion:** IHD is the ratio between RMS value of the individual harmonic content and the RMS value of the fundamental voltage expressed in percentage.

$$IHD = \sqrt{\frac{v_i^2}{v_1^2}} * 100\%$$

v_i = Voltage component of harmonic order i;

v_1 = Voltage component of fundamental frequency (50 Hz).

84) **Information Owner:** The party to whose system or installation the information pertains.

85) **Information Service Provider (ISP)**: The entity that has the functions of installing, operation management, maintaining the equipment related to the information transmission channel from the generation entities to the Metering Data agent in the power market.

86) **Interconnected System:** It is a system consisting of two or more individual electric systems that normally operate in synchronism and that have connecting tie-lines.

87) **Interruption (of supply):** An interruption, not requested by the customer, of the flow of power to a point of supply for a period exceeding 3 seconds.

88) **Island:** A portion of a power system or several power systems that is electrically separated from the inter-connection due to the disconnection of transmission network equipment.

89) **Least-economic cost:** The lowest value of the sum of the life cycle costs to both the Distributor and the customer related to various options for the supply of electricity.

90) **Losses:** Refers to energy for which the TNO or DC does not recover revenue. Losses include Technical losses, non-technical losses and administrative losses.

91) **Least life cycle costs:** The lowest sum of all cost categories from installation to decommissioning when evaluating the different investment alternatives for the supply of electricity.

92) **Load Shedding:** Controlled interruption of power supply to Customers in order to reduce consumed power in power system.

93) **Load increasing rate:** The maximum rate that the generator can increase its output, as measured over a period of 15 minutes in normal working conditions.

94) **Load decreasing rate:** Maximal reduction of generated power of one generator unit or power plant as measured over a period of 15 minutes in normal working conditions.

95) **Lost frequency fault:** Emergency situation of the power system when frequency in the power system falls below 49.5 Hz.

96) **Low frequency automatic load shedding**: Load shedding acted by low frequency relays.

97) **Low voltage (LV):** Nominal voltage levels up to and including 1 kV.

98) **Main metering system**: The primary metering system used as evidence to determine and settle the official electrical energy.

99) **Market Operator (MO):** Party responsible for administering determining the economic merit order of generation in the Sierra Leone Electricity Market.

100) **Market Rules:** The rules for trading of electricity in the Sierra Leone Electricity Market as issued appropriately by the Electricity and Water Regulatory Commission (EWRC) of Sierra Leone.

101) **Maximum voltages (U_{max}):** Maximum continuous operating voltage.

102) **Medium voltage (MV):** The set of nominal voltage levels greater than 1 kV up to and including 33 kV.

103) **Measuring circuit:** Electrical circuit system that connects the equipment that has the functions of metering.

104) **Meter:** Device which measures the capacity integration by time, archive and exhibit the metered electricity value. In this Grid Code, it is understood as the electrical, or electronic, meter.

105) **Metering activity**: The process of energy measurement including the installation, metering, collecting and processing the off-taken and trading data.

106) **Metering Data Management Service Provider (MDMSP):** Entity that has functions of installing, maintaining, operating the data collection systems, operating and archiving the metering data for serving the power market activities.

107) **Metering equipment:** Equipment including meter, CT, VT and any associated ancillaries necessary for power measurement.

108) **Metering Point**: Physical location(s) on the primary power circuit, where electrical energy is measured and defined.

109) **Metering Service Provider:** A legal entity contracted by the TNO or DC to provide metering services.

110) **Metering Site:** Overall metering location associated with metering a connection point, and includes main and back up metering points.

111) **Metering system**: System including the equipment and circuit integrated for metering and defining the electricity volume at a metering point in the connection point.

112) **Metering Test Service Provider (MTSP):** Entity that has functions of monitoring, testing, inspecting and adjusting the metering equipment and metering systems of the generator.

113) **Minimal time for system separation:** Shortest time necessary for putting back generator unit into operation after being separated from the transmission network.

114) **Minimal generated capacity:** Lowest generated capacity level which is safe operation of power generation unit can be maintained within a long period.

115) **Minimum voltages (U_{min}):** Minimum continuous operating voltage

116) **National Power Development Plan**: A plan for national power development that has been prepared appropriately by EWRC.

117) **National Power System Operating Procedure:** A document jointly issued by the TNOs and SO from time to time defining procedures for information exchange necessary for safe and efficient operation of the power system.

118) **Network:** Set of transmission lines, transformers and other equipment linked to each other to transmit power.

119) **Network charges:** Charges designed to recover costs (including capital, operations, maintenance and refurbishment) associated with the provision of network capacity required by and reserved for the customer which may or may not be unbundled.

120) **Network service customers:** Customers receiving only a network service from a DC.

121) **Nominal voltage:** The voltage by which the system is designated and to which certain operating characteristics are related, and the voltage at which the system operates and is normally about 5 to 10 percent below the maximum system voltage for which system components are designed.

122) **Non-dispatchable renewable generation:** Any generator whose input is from wind and solar and whose output is set by the real time availability of those sources.

123) **Non-technical losses:** Losses due to theft of electrical energy and errors due to inaccuracy of meters and administrative losses.

124) **Normal operating conditions:** An operating condition where the system frequency, voltage and equipment loading are within their statutory, contractual and/or design limits and no network component on the relevant part of the Distribution System is out of service due to a forced outage.

125) **Offer to connect:** A quotation issued by the Distributor to the applicant indicating the technical and commercial conditions upon which a connection agreement can be entered into.

126) **Operational characteristics**: Combination of parameters determining response of a turbine-generator unit to dispatch instructions for operation of the unit.

127) **Operation mode:** Anticipated electricity consumption, power generation plan and operation schedule of power transmission lines and substation determined and announced by the SO after getting consensus with power generation agencies, power transmission agencies.

128) **Operating Reserve:** The additional megawatt output required from a generation unit or demand reduction which must be realizable in ten (10) minutes time operation to contain and correct any potential power system frequency deviation to an acceptable level.

129) **Operating standards:** Regulations on economic, technical indicators, synchronization, safety and reliability of the power system promulgated by competent state agencies for preparing plans, operation modes and generation of the power system.

130) **Operating voltage:** System voltage at specific point in specific time.

131) **Overall dependability:** In the context of an automatic under frequency load shedding system, is the mean expected level of total response of the load shedding scheme to a load shedding signal.

132) **Password at level "Read only":** Level that allows to access to the meter to read the data, but does not allow any change to time synchronisation, the installed parameters and the operating program of the meter.

133) **Password at level "synchronizing time clock":** Level that allows to access to the meter to read the data and make its time clock synchronously; this password level does not allow changes to the installed parameters and the operating program of the meter.

134) **Password at level "Setting":** The level that allows access to the meter to install, change the installed parameters and the operating program of the meter.

135) **Partial system blackout:** Loss of power in one or more parts of the transmission network, but not all parts of the transmission network.

136) **Participants:** As defined in the Code

137) **Peak load:** Highest consumption power capacity of electricity users.

138) **Person:** includes an individual, a company, partnership or any association of individuals, whether incorporated or not;

139) **P_{lt}95%:** Value of P_{lt} so that in 95% of time (at least one week) and 95% of places the measured values of P_{lt} do not exceed.

140) **Planned outages:** An outage of equipment that is requested, negotiated, scheduled and confirmed prior to the maintenance or repairs taking place.

141) **Point of Common Coupling (PCC):** The electrical node where more than one customer is connected.

142) **Point of Connection (POC):** Point on a public power supply system where the installation under consideration is, or can be connected. It can also be considered as the electrical node on a transmission or distribution system where a customer's assets are physically connected to the TNO's or DC's assets. Note that, a supply system is considered as being public in relation to its use, and not its ownership.

143) **Point of Supply:** Physical point on the electrical network where electricity is supplied to a customer.

144) **Power demand:** Active power P and reactive power Q anticipated for meeting demand of electricity users.

145) **Power factor:** Ratio between active power P and scalar product of voltage (U) and current (I).

146) **Power Master Plan:** Plan for development of the power system, developed by EWRC.

147) **Power Pool Operator**: The party authorised by the West African Power Pool (WAPP) rules for trading in the WAPP.

148) **Power Quality:** Characteristics of the electricity at a given point on an electrical system, evaluated against a set of reference technical parameters. These characteristics include:

- voltage or current quality, i.e. regulation (magnitude), harmonic distortions, flicker, unbalance;
- voltage events, i.e. voltage dips, voltage swells, voltage transients;
- (supply) interruptions;
- frequency of supply.

149) **Power Station Supply:** A supply of power to the plant of a generator or embedded generator, that is separate and independent of the network into which it normally supplies the power that it generates. This supply could be from the Distribution System or the Transmission System.

150) **Power system**: Combination of facilities of power generation, transmission, distribution, automation, and communication which are connected into one common network throughout the country.

151) **Power system of customer using transmission network**: Facilities managed and operated by customer using transmission network, which are connected to the transmission network and forming a part of the power system.

152) **Power System Stabilizer (PSS):** Device that injects a supplementary signal into the AVR (Automatic Voltage Regulator) in order to improve power system damping.

153) **Premium supply / premium connection:** Where the customer's requirements exceed the specifications of a standard supply.

154) **Primary Frequency Control:** Frequency controlling action performed by the governor of the turbine of generating units in accordance with the frequency change and speed of change.

155) **Protection System Dependability Index:** Measure of the ability of protection system to initiate successful tripping of circuit breakers that are associated with the faulty items of equipment;

156) **P_{st}:** A measure of power system quality, referred to as flicker, as defined by standard IEC 61000-4-15.

157) **P_{st}95%:** Value of P_{st} so that in 95% of time and places the measured values of P_{st} do not exceed.

158) **Ramp Rate:** The rate of change at which the power output of a generator can be increased or decreased (in MW/min).

159) **Rated Power:** Is the rated installed power capacity of a generating unit that is connected to the network and whose output is continuously available to the network. Rated power (of a VRPP): The highest active power measured at the POC, which the VRPP is designed to continuously supply.

160) **Rated wind speed:** The average wind speed at which a wind power plant achieves its rated power. The average renewable speed is calculated as the average value of renewable speeds measured at hub height over a period of 10 minutes.

161) **Reactive power:** Multiplication of voltage (U), the phase component of AC current (I) and the sine of the angle between U and I. Reactive power capacity is measured in VAr and symbolized by letter "Q".

162) **Reliability:** Ability of a power system to continuously supply power to its consumers.

163) **Remote Terminal Unit (RTU):** Unit installed in substation for the purpose of collecting and transmitting data to Master Computer of SCADA/EMS, SCADA/DMS system.

164) **SCADA System:** Supervisory Control and Data Acquisition System.

165) **Seal:** Result of sealing and secured clipping positions that must be secured e.g. terminals, kiosks, terminal box cover.

166) **Security constrained economic dispatch (SCED):** Process of dispatching generators to meet the forecast load at least total cost while meeting all security requirements.

167) **Self capacity regulation:** Expected range of generated power level variation over which primary frequency control of generator is expected to operate.

168) **Seller:** Any party licenced to sell electricity to consumers in a designated area.

169) **Separation from power system:** Operation of shutting down the unit or power plant, or elements of power system in order to temporarily separate them from the transmission network.

170) **Serious fault:** Fault causing power loss in a wide area or in the whole power system, or causing fire, explosion, damaging to people and property.

171) **Service provider**: An entity providing a contracted or licensed service.

172) **Sierra Leone Electricity Market (SLEM):** The arrangements for buying and selling of wholesale electricity in Sierra Leone as defined by the Electricity and Water Regulatory Commission (EWRC) from time to time.

173) **Standard connection charge:** The connection charge associated with the costs of providing a standard supply.

174) **Standard connection / standard supply:** A standard connection is defined as the lowest life-cycle costs design that meets the specifications in terms of quality of supply and technical performance standards.

175) **Start-up time:** Shortest time necessary for starting up a generator unit from receiving dispatch instruction to start up the unit until the generator unit completed synchronizing with the transmission network.

176) **Significant embedded generator:** Generator with generating units connected directly to the distribution network where the total installed capacity of the generating units at any one point of connection to the distribution network exceeds 2MW.

177) **Single Contingency:** Includes the singular that involves,

(i) sudden, unexpected failure or outage of any single component of a power system, like generating unit, transmission line, transformer, etc.; or

(ii) removal from service of an element of the power system like generating unit, transmission line, transformer etc. as part of the operation of a remedial action scheme, the occurrence of which shall not affect the normal operation of the TNO's network.

178) **Stabilizer**: Equipment connected to generator in order to enhance stability of the power system.

179) **Spinning reserve:** Reserve capacity at generator unit operating in the power system, which is available for use by the SO within stipulated time.

180) **Synchronize:** The process of connecting two or more previously separated alternating current apparatuses after matching frequency, voltage and phase angles like paralleling a generator to the electric system.

181) **Synchronizing:** Action to connect a generating unit to a power system or to connect two parts of a power system following the adjustment in frequency, voltage and phase angle so that the difference are within allowable limits.

182) **System Operator (SO):** Party licenced to operate and control the national electricity network and is the unit responsible for controlling the power generation (balancing the supply and demand in real-time), transmission and distribution within the national power system according to the decided operation modes and procedures.

183) **System Protection Dependability:** A measure of the ability of protection to initiate successful tripping of circuit-breakers which are associated with a faulty item of apparatus. It is calculated by using the formula:

$$D_p = 1 - F_1/A$$

Where: A = Total number of faults

F_1 = Number of system faults where there was a failure to trip a circuit breaker.

184) **Tariff structure:** The makeup of the tariff that contains all the components of price and the relationship to consumption and demand

185) **Technical Losses:** Losses intrinsic in transporting electrical energy (that is, heating and no-load losses etc.)

186) **Total Harmonic Distortion:** THD shall be defined as the ratio of the RMS voltage of the harmonic content to the RMS value of the fundamental voltage, expressed in percent.

$$THD = \sqrt{\frac{\sum V_i^2}{V_1^2}} * 100\%$$

THD = Total Harmonic Distortion of voltage;

V_i = Voltage component of harmonic order i;

V_1 = Voltage component of fundamental frequency (50 Hz).

187) **Trader:** Any entity, licenced to carry out the function of wholesale purchasing from the generation entities in the market, while reselling to the sellers.

188) **Transmission Expansion Plan (TEP)**: Plan for investment in the transmission network as produced annually by the TNOs in accordance with Chapter V.

189) **Transmission Network:** The system consisting of (major part or the system as a whole) lines and cables, having design voltage of higher than 66 kV, operated and managed by a TNO to transmit energy from a generating station to a substation or to another generating station or inter-substations or to any interconnection system including apparatus, equipment and metering systems owned by a TNO to use for transmission of energy.

190) **Transmission Network Operator (TNO):** Party licenced to operate a Transmission Network. They are responsible for operation, maintenance, and investment in the transmission network.

191) **Total system blackout:** Loss of power in all parts of the transmission network.

192) **Under Frequency Automatic Load Shedding System:** Set of equipment for the purpose of Load Shedding which is achieved by the operation of the Under Frequency Relay.

193) **Unrestricted Operation Range:** Normal network frequency or voltage operating range during which no generating unit is allowed to disconnect and where there is no technical restriction with regard to the delivery of active power or reactive power.

194) **User:** Generator, Power Pool Operator, Distribution Company, Direct Connected Consumer, Trader or Seller, who requests connection to Transmission Network, or is connected to the Transmission Network.

195) **Under Frequency Relay**: Automatic equipment set for tripping when frequency of power system falls lower than a certain value set in advance in order to control frequency of the power system.

196) **Variable Renewable Power Plant (VRPP):** Renewable power plants with continuously varying power output following the availability of primary energy without any storage (Wind and solar PV farms).

197) **Variable Renewable Power Plant (VRPP) Controller:** A set of control functions that make it possible to control the VRPP at the POC. The set of control functions shall form a part of the VRPP.

198) **VRPP Generator:** Means a legal entity that is licensed to develop and operate a VRPP.

199) **VRPP Applicant / VRPP Owner / IPP:** The owner of a generation facility or an independent power producer (IPP) seeking connection with the TNO's network or DC's network to interconnect their facility with transmission network or distribution network.

200) **VRPP Operator:** Operator of a VRPP seeking connection to or already connected to the TNO's or DC's network.

201) **Voltage Control:** The control of system voltage within acceptable limits through adjustments in generator reactive output or by transformer tap changing or by switching.

202) **Voltage Quality:** Subset of power quality referring to steady-state voltage quality, i.e. voltage regulation (magnitude), voltage harmonics, voltage flicker, voltage unbalance, voltage dips. The current drawn from or injected into the POC is the driving factor for voltage quality deviations.

203) **Voltage Ride Through (VRT) Capability:** Capability of the VRPP to stay connected to the network and keep operating following voltage dips or surges caused by short-circuits or disturbances on any or all phases in the TS or DS.

204) **Voltage selector**: Selector or an auxiliary relay's contact with selecting voltage function.

205) **Voltage Regulatory System:** A centralized control system at a VRPP that measures voltage compared to a set point voltage and controls reactive power devices.

206) **Voltage transformer (VT):** An instrument transformer in which the secondary voltage, in normal conditions of use, is substantially proportional to the primary voltage and differs in phase from it by an angle which is approximately zero for an appropriate direction of the connections.

207) **Website:** Official website of the SO for publication of market related information.

Article 1. Objective

This Interim Grid Code lays out the requirements, standards, procedures, and conditions related to planning, connection, dispatching, safe, stable and efficient operation, and metering of the National Power Grid. It also states the relationship between the institutions and / or individuals who manage the planning and operation of the national power system and institutions and / or individuals who use the transmission network, and boundaries of operation with international power pool operation, as part of West African Power Pool (WAPP).

Article 2. Provision for West African Power Pool

This Interim Grid Code allows for separate parties to own the transmission interconnection to the WAPP (as a separate TNO) and another separate party to operate (schedule and dispatch power transfers within the pool) the WAPP, as a power pool operator.

Article 3. Guiding Principles and Purpose

Operation and governance of this Interim Grid Code is to be in accordance with Articles 4 and 5 below. All governance and dispute resolution bodies will take into account the purpose statement and guiding principles when:

a) Considering any proposed amendments to the Interim Grid Code;

b) Considering any dispute arising under the Interim Grid Code; or

c) Considering any exemption to the Interim Grid Code.

Article 4. Purpose Statement

The purpose of this Interim Grid Code is to promote open, transparent and fair access to the Grid by:

a) Defining a transparent set of technical standards for Transmission Network connection;

b) Defining a transparent set of security standards for dispatch; and

c) Defining a transparent set of operational standards for Transmission Network Connections and Dispatch.

d) Defining a transparent set of conditions for Distribution Network Connection and Operation; and

e) Defining a transparent set of conditions for the integration of renewable energy plants into the Transmission Network and for embedding into the Distribution Network.

Article 5. Guiding Principles

The guiding principles of the Interim Grid Code are that the Interim Grid Code should:

a) Ensure all parties connected, or seeking connection, to the Transmission Network(s) are treated in a fair and equitable fashion;

b) Promote transparency in the process for connection to the Transmission Network(s), and operation of the Transmission Network(s);

c) Promote transparency in the process for connection to the Distribution Network, and operation of the Distribution Network; and

d) Foster economic efficiency in the development and operation of the power system.

Article 6. Parties Bound by this Interim Grid Code

The following parties are bound by this Interim Grid Code:

a) The Transmission Network Operators (TNOs), including any West African Power Pool (WAPP) interconnection operators;

b) The System Operator (SO);

c) The Market Operator (MO);

d) All generators with assets directly connected to the Transmission network;

e) The West African Power Pool operator to the extent that their operation impacts the Sierra Leone electricity network;

f) Significant embedded generators;

g) All Distribution Companies (DCs) with equipment connected to the Transmission Network(s);

h) Traders;

i) Sellers; and

j) Consumers with assets directly connected to the Transmission Network(s) (Directly Connected Consumers (DCCs) or Eligible Customers).

Article 7. Hierarchy

1) The contents of this article are included for information only. For the guidance of parties to this Grid Code it is noted that the hierarchy of documents related to this Grid Code is as follows, from highest to lowest:

a) The law;

b) The Operating Licence of the connected entity;

c) This Interim Grid Code

Chapter II. Governance

Article 8. EWRC Constitutes Grid Advisory Committee

EWRC shall from time to time constitute a Grid Advisory Committee (GAC) to assist EWRC with the process of developing recommendations for amendment of this Interim Grid Code. The GAC shall comprise 9 members.

Article 9. Make Up of GAC

The Grid Advisory Committee (GAC) shall be made up of stakeholder representatives of parties to the Interim Grid Code as follows:

a) TNO(s) – 1 member

b) SO – 1 member

c) Non-IPP Generators – 1 member

d) IPP Generators – 1 members

e) DCs – 1 member

f) Power Pool Operators - 1 member

g) Traders - 1 member

h) DCCs– 1 member

i) EWRC – 1 member

Article 10. Process for GAC Approval

1) All stakeholder shall nominate their member(s) to EWRC for approval.
2) EWRC shall consider and advise, within 5 working days, whether to approve a nominated member.
3) Where EWRC does not approve a nominated member the nominating party may nominate an alternative within 5 working days.
4) EWRC may only refuse a maximum of 3 nominations for any one position for any period.
5) For generator, consumer (DC or DCC), trader or power pool operators' representatives, the nominated members shall be selected by the collective members of that class of stakeholder by a simple majority voting process.
6) Membership of the GAC shall be for a term of 2 years.
7) In the event a member quits, whether by resignation, death or otherwise, whosoever comes in in replacement, will serve the remainder of the 2 years term.

Article 11. Duties of GAC

1) The GAC may develop its own procedures for operating, including but not limited to:
   a) Appointment of chair;
   b) Process for reaching decisions;

c) Processes for consultation;
d) Any record keeping and operating procedures.

2) When directed by EWRC the GAC is to consider and advise EWRC on any proposed changes to this Interim Grid Code. In doing so it will:
   a) Take due account of the purpose and guiding principles;
   b) Consult the TNO(s), SO, and grid users concerning the impact of the proposed change on them. Such consultation must include but not be limited consideration of costs imposed and ability to meet obligations and targets imposed by this Interim Grid Code;
   c) Advise EWRC on whether it considers the proposed change:
      i) Furthers the purpose and guiding principles;
      ii) Is in accordance with the technical conditions of the power system; and
      iii) Is in the best economic and technical interests of all parties to the Interim Grid Code.
   d) If the GAC recommends a proposed change to EWRC then it shall also provide advice to EWRC on responsibilities and allocation of any costs arising from or related to the proposed change.
3) The GAC shall seek to come to a consensus view on its recommendation to EWRC.
4) Where a consensus view is unable to be reached it will determine its recommendation to EWRC by majority vote.
5) Any dissenting vote, and the reasons for the dissent, will be noted in the recommendation to EWRC.

Article 12. Interim Grid Code Change Process

1) Any person may propose a change to this Interim Grid Code. Such a proposal must:
   a) Be addressed to EWRC;
   b) Include a detailed description of the proposed change;
   c) Include the reasons for the proposed change; and
   d) Include a statement of how the proposed change promotes the purpose and guiding principles of the Interim Grid Code.
2) EWRC must consider any such proposal. In considering such a proposal the EWRC:
   a) Shall consult the Grid Advisory Committee (GAC); and
   b) Must take account of the purpose and guiding principles of the Interim Grid Code.

Article 13. Timing of Interim Grid Code Change Process

Within 120 days of receiving a proposal the EWRC must publish its decision regarding a change to the Interim Grid Code, and the reasons for its decision.

Article 14. EWRC to Consider GAC Advice

EWRC will take due consideration of any advice from the GAC in developing recommended changes to the Interim Grid Code.

Article 15. GAC Recommendations to EWRC

All GAC advice to EWRC must be approved by majority vote. Where advice is not unanimous the GAC will note, in its advice to EWRC any party that voted against the advice and the reason for that vote.

Article 16. EWRC Process for consideration of proposed changes

In considering any proposed change, the EWRC must:

a) Take due account of the purpose and guiding principles;
b) Where it has directed GAC to consider the proposed change, then consider the advice of GAC, including any dissenting views within GAC;
c) Where it has not directed the GAC to consider the proposed change, it must consult the TNO(s), SO, and grid users concerning the impact of the proposed change on them. Such consultation must include but not be limited consideration of costs imposed and ability to meet obligations and targets imposed by this Interim Grid Code;
d) Consider whether the proposed change is consistent with:
    i) The current state of the power system; and
    ii) State policy.
e) Consider responsibility and the allocation of any costs associated with or arising from the proposed change.
f) Where it has directed GAC to consider a proposed change, then include a copy of GAC advice in any final decision and note where its decision may differ from the GAC advice; and
g) Advise all stakeholders on its final decision regarding the proposed change.

THE TRANSMISSION SUB – CODE

Chapter III. Power System Performance Standards

This section provides further reporting requirements for the SO and TNO(s), in addition to those provided under the Electricity (Quality of Supply) Regulations. This additional reporting is to all stakeholders, and provides them additional information on SO and TNO(s) performance. Further detail of measurements and reporting is provided in Chapter IX. In the Grid Code, no performance incentive is proposed (see Chapter IX). However the reported information could form the basis of future performance incentives if desired.

Section a. System Operator Performance Targets

Article 17. Purpose of SO Performance Targets

In operating the power system, in accordance with Chapter VI, the SO shall endeavor to ensure the power system performance targets specified in this section are met.

Article 18. Reporting on Performance Against Targets

The SO shall, from time to time, report on its performance in meeting these targets as laid out in Article 151.

Article 19. System Frequency

1) The frequency of power system shall be nominally 50 Hz and should be controlled within the following limits:

Power System Operating State	Normal Operating State	First Contingent Event	Multiple Contingent Events, or Grid Emergency
Frequency Range	49.8 Hz to 50.2Hz	48.5 to 51.5 Hz	47.0 Hz to 53.0 Hz

2) The aggregated deviations outside this limit should be within the following expected statistical levels:

Frequency Band (Hertz) (where "x" is the frequency during a momentary fluctuation)	Maximum number of occurrences by period (commencing on and from the commencement date)
52 > x ≥ 51.25	7 in any 12 month period
51.25 > x ≥ 50.5	50 in any 12 month period
49.5 ≥ x > 48.75	60 in any 12 month period
48.75 ≥ x > 48	6 in any 12 month period
48 ≥ x > 47	1 in any 60 month period

Section b. Transmission Network Operator Performance Targets

Article 20. Purpose of TNO(s) Performance Targets

In design and operation of the Transmission Network each TNO shall endeavor to ensure the system performance targets specified in this section are met.

Article 21. Reporting on Performance Against Targets

Each TNO shall, from time to time, report on its performance in meeting these targets as laid out in Article 152.

Article 22. Reliability Standards

1) The unserved energy for any one year should not exceed the annual target MWhs as defined by EWRC from time to time.
2) Unserved energy shall be measured as load that was interrupted due to an unplanned outage of a transmission network asset where:
    a) The interrupted load (in MWhs) shall be the actual MWs interrupted at the start of the unplanned outage times the duration (in hours) of the unplanned interruption;
    b) The duration of the outage exceeded 1 minute;
    c) The loss of supply was not primarily due to any unavailability of generation;
    d) The loss of supply was solely due to an unplanned outage of a transmission network asset;
    e) A planned outage is any outage for which there was more than 7 days' notice; and
    f) The unplanned outage was not due to an extreme weather event.
3) EWRC shall notify the TNOs of any event it considers to be an extreme weather event.
4) EWRC shall determine the annual reliability target of unserved energy to be used in 1) above from time to time.
5) In doing so EWRC shall:
    a) Consult the TNO(s), SO and all Users;
    b) Seeking advice from the TNO(s) on any impact on transmission costs of a proposed target; and
    c) Give due consideration of the costs and quality of supply preferences of all Users.

Article 23. System Loss Standards

1) The average system losses should not exceed the annual loss target when calculated according to the following formula:

$$Losses = \frac{(Total\ transmission\ network\ inputs\ for\ the\ year - Total\ transmission\ network\ exports\ for\ the\ year)}{\text{Total transmission network inputs for the year}}$$

2) Where:
    a) Total transmission network inputs is the metered value of energy input to the transmission network from all transmission network connected generators, adjusted to the relevant connection point for each generator, plus the metered value of transmission network energy imports from other nations, adjusted to the relevant import point; and
    b) Total transmission network exports for the year is the metered energy value of energy exported from the transmission network, adjusted to the relevant connection point for each DC and DCC, plus the metered value of transmission network energy exports to other nations, adjusted to the relevant export point.

3) EWRC shall determine the annual loss target of energy to be used in 1) above from time to time.
4) In doing so EWRC shall:
    a) Consult the TNO(s), SO and all users;
    b) Seeking advice from the TNO(s) on any impact on transmission costs of the proposed target; and
    c) Give due consideration of the costs and quality of supply preferences of all Users.

Article 24. Voltage Unbalance

The maximum negative sequence component of the phase voltages shall not exceed 2% of the nominal value during normal conditions.

Article 25. Short Circuit Current and Fault Clearance Time

1) Unless otherwise approved by EWRC, maximum allowable short circuit current and maximum fault clearance time, at the connection point, by main protections in transmission system are specified in Table *1*.

Table 1: Short Circuit Current and Fault Clearance Time

Voltage level	Maximum short circuit current (kA)	Maximum fault clearance time (ms)
225 kV	40	100
161 kV	31.5	150
66 kV	30	250
33 kV, 11 kV	25	300

2) A TNO may propose to EWRC a maximum fault level or fault clearance time different from that specified in Table 1for specific substations where it reasonably considers such a fault level or clearance time would result in a lower overall cost of supply to end

consumers. Such a proposal shall demonstrate the overall cost benefit to end consumers of such a different fault level or clearance time.

3) EWRC shall duly consider any such proposal and consult all affected users. Where it considers such a proposal would result in a lower overall cost to end consumers it may approve a fault level or clearance time different from the default level or clearance time for a specific substation.

Article 26. Harmonics

1) Harmonics are defined as sinusoidal voltages and currents having frequencies that are integer multiples of the fundamental frequency.

2) The total harmonic distortion (THD) is defined as the ratio of the RMS value of the harmonic content to the RMS value of the fundamental, expressed in percent.

3) The total demand distortion (TDD) is defined as the ratio of the RMS value of the harmonic content to the RMS value of the rated or maximum fundamental quantity, expressed in percent.

4) The total harmonic distortion of the voltage and total demand distortion of the current at any connection point shall not exceed the limits given in Table 2.

Table 2: Harmonic Voltage and Current Distortion

Voltage level	Total Harmonic Voltage Distortion THD	Total Harmonic Current Distortion TDD
11, 33, 66, 161, 225 kV	3%	3%

5) The TNOs collectively have overall responsibility for harmonic control in the whole system so that the harmonic distortion levels in the system shall not exceed the values stated in Table 2 in normal system conditions. The TNOs shall co-operatively determine how this responsibility is to be determined. If agreement cannot be reached EWRC may make a determination. Each TNO has responsibility for ensuring its equipment does not inject harmonics onto the network beyond the levels specified in Table 2. Parties connected to the transmission network have responsibility for ensuring their connected equipment does not inject harmonics onto the transmission network beyond the levels specified in Table 2.

6) Where a connected party considers the above harmonic standards are not being met at any connection point it may request the relevant TNO to investigate the source of any such harmonics. The relevant TNO must investigate and attempt to remedy any such breaches to the extent permitted within this Grid Code. Where it can identify the source of such harmonic distortion it may recover the full cost of such investigations from the causer. Where it concludes that the standards have not been breached it may recover the full costs of investigation from the party requesting the investigation. Otherwise it will bear such investigation costs itself.

Article 27. Voltage Fluctuations and Flicker Severity

1) Voltage fluctuations are be defined as the systematic variations of the voltage envelope or random amplitude changes where the RMS value of the voltage is between 90% and 110% of the nominal voltage.

2) Flicker is defined as the impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.

3) The measurement of long term flicker shall be derived from the measurement of short term flicker. Short term flicker shall be measured by the term flicker severity short term (P_{st}). Long term flicker shall be measured by the term flicker severity long term (P_{lt}).

4) The voltage fluctuation at any connection point serving demand shall not exceed 1% of the nominal voltage for every step change, which may occur repetitively. Any large voltage fluctuation, other than a step change, may be allowed up to a level of 3% of the nominal voltage, provided this does not constitute a risk to the transmission network or the equipment of any connected party.

5) The maximum allowable flicker severity at any connection point shall not exceed the levels stated in Table 3.

Table 3: Flicker Severity

Voltage level	**P_{lt}95%**	**P_{st}95%**
11, 33, 66, 161, 225 kV	0.6	0.8

6) TNOs collectively have overall responsibility for flicker severity control in the whole system so that the flicker severity levels in the system shall not exceed the values stated in Table 3 in normal system conditions. The TNOs shall co-operatively determine how this responsibility is to be determined. If agreement cannot be reached EWRC may make a determination. Parties connected to the transmission network have responsibility for ensuring their connected equipment does not cause flicker on the transmission network beyond the levels specified in Table 3.

7) Where a connected party considers the above flicker standard is not being met at any connection point it may request the relevant TNO to investigate the source of any such flicker. The relevant TNO must investigate and attempt to remedy any such breaches to the extent permitted within this Grid Code. Where it can identify the source of such flicker it may recover the full cost of such investigations from the causer. Where it concludes that the standards have not been breached it may recover the full costs of investigation from the party requesting the investigation. Otherwise it will bear such investigation costs itself.

Article 28. Ground Fault Factor

At nominal voltages of 66 kV and above the ground fault factor at the connection point shall not exceed 1.4. At nominal voltages below 66 kV the relevant TNO shall specify the ground fault factor at the connection point.

Article 29. Neutral Grounding

Sierra Leone transmission system is a solidly grounded system.

Section c. Joint TNOs and SO Performance Targets

This section allows for the TNOs and SO to be separated if desired.

Article 30. Purpose of Joint Performance Targets

In the design and operation of the power system as a whole the TNOs and SO shall jointly endeavor to ensure the system performance targets specified in this section are met.

Article 31. Reporting on Performance Against Targets

The TNOs shall, from time to time, report on the joint performance of the SO and TNOs in meeting these targets as laid out in Article 152 and Article 151.

Article 32. System Voltage

1) The nominal voltage levels in transmission system are as follows: 225 kV, 161 kV and 66 kV.
2) System voltage variations in normal conditions or contingency outages shall be as stated in Table 4:

Table 4: Stipulated Voltage Value

Voltage level	**Normal conditions**	**Single Contingency Outages**	**Multiple Contingency Outages, or Grid Emergency**
225 kV	213.75 kV – 236.25 kV	202.5 kV – 247.5 kV	May temporarily exceed 202.5 kV – 247.5 kV
161 kV	152.95 kV – 169.05 kV	144.9 kV - 177.1 kV	May temporarily exceed 144.9 kV - 177.1 kV
66 kV	62.70 kV – 69.00 kV	59.4 kV – 72.6 kV	May temporarily exceed 59.4 kV – 72.6 kV

3) During ground fault conditions, voltage at the fault location and vicinity may fall transiently to zero on the faulted phase(s) or rise transiently beyond 110% phase to ground voltage on the unfaulty phase (s) until the fault has been cleared.
4) Voltage variations may temporarily exceed ± 15% during severe emergencies and restoration for periods up to a maximum of 1 minute.
5) Voltage fluctuations caused by non-periodical fluctuating demand shall not exceed 2.5% of operating voltage at the connection point.

Article 33. Safety Standards

1) The power system shall, at all times, be operated in a safe and efficient manner so as to:
   a) Comply with the obligations of the Electricity Law, and any electrical safety regulations and electrical safety procedures applicable in Sierra Leone;
   b) Protect human life;
   c) Protect connected equipment; and
   d) Safeguard the environment.
2) The TNOs and SO shall publish operating procedures laying out how such safe operation of the power system is to be achieved. All connected parties are bound to abide by these procedures.
3) Review of the safety standards will be required when the need arise.

Section d. Connected Party Performance Obligations

To meet its own quality of supply obligations the TNOs have to be able to impose quality of supply obligations on connected parties, as these affect other parties connected to their grid.

Article 34. Technical Obligations

In order for the SO and TNOs to achieve their performance targets all parties connected to the transmission network need to meet the technical obligations laid out in this section and in Chapter IV Section f.

Article 35. System Voltage

1) Unless otherwise agreed in a connection agreement, voltage variations in at the connection point shall be as stated in Table 5, or as specified from time to time in the quality of supply regulations:

Table 5: Stipulated Voltage Value

Voltage level	Normal conditions	Single Contingency Outages
225 kV	± 5%	± 10%
161 kV	± 5%	± 10%
66 kV	± 5%	± 10%
33 kV	± 6%	± 10%
11 kV	± 6%	± 10%

2) During ground fault conditions, voltage at the fault location and vicinity may fall transiently to zero on the faulted phase(s) or rise transiently beyond 110% phase to ground voltage on the unfaulted phase (s) until the fault has been cleared.
3) Voltage variations may temporarily exceed ± 10% during severe emergencies and restoration.

Article 36. Voltage Unbalance

The maximum negative sequence component of the phase voltages shall not exceed 2% of the nominal value during normal conditions.

Article 37. Neutral Grounding

Neutral grounding in the Generators, DC's and DCC's connected power systems are stipulated in Table 6.

Table 6: Neutral Grounding Arrangements

Voltage level	Neutral point
33 kV	Solidly grounded or grounded through resistor / reactor
11kV	Solidly grounded

Article 38. Short Circuit Current and Fault Clearance Time

The maximum allowable short circuit current and maximum fault clearance time, at the connection point, by main protections in connections to the transmission system are specified in Table 7.

Table 7: Short Circuit Current and Fault Clearance Time

Voltage level	Maximum short circuit current (kA)	Maximum fault clearance time (ms)
Below 66 kV	25.0	300

Article 39. Ground Fault Factor

The ground fault factor for connections to the transmission network, at the point of connection to the transmission network, shall not exceed 1.4. Or as specified from time to time in the quality of supply regulations.

Article 40. Harmonics

The maximum levels of harmonics distortion (in percent of nominal value) from all sources shall be as stated in Table 8. Or as specified from time to time in the quality of supply regulations.

Table 8: Harmonic Voltage Distortion

Voltage level	THD
Below 66 kV	5.0%

Article 41. Flicker Severity

The maximum allowable flicker severity shall be as stated in Table 9. Or as specified from time to time in the quality of supply regulations.

Table 9: Flicker Severity

Voltage level	P_{lt}95%	P_{st}95%
Below 66 kV	0.8	1.0

Chapter IV. Connection to the Transmission Network

Section e. Conditions of Connection to the Transmission Network

Article 42. Investment Responsibilities

1) Unless otherwise agreed prior to this Grid Code coming into force, or in a connection contract, the following principles shall apply:
    a) For connections to a generator the relevant TNO is responsible for investment up to and including the point at which the generating unit connects to a bus bar designed to operate at a voltage of 66 kV or higher. Such investment shall be of a technical standard to ensure the connection meets the network performance criteria in Article 22 to Article 33.
    b) For connections to other connected parties the relevant TNO is responsible for investment up to and including the point at which a supply transformer connects to a bus bar designed to operate at a voltage of 66 kV or higher.
2) The details of the investment boundary shall be as agreed between the user and the relevant TNO, according to the above principles, and recorded in detailed drawings, diagrams and documentation as part of the connection agreement.
3) For clarity it is noted that the investment boundary may not be the connection point.

Article 43. Connection Point

1) The connection point is the point which connects the user's equipment, network and generating units to the transmission network.
2) The connection point shall be described with detailed drawings, diagrams and documentation in the connection agreement.

Article 44. Ownership Boundary

1) The connection point shall be the ownership boundary between the transmission network operator and the user.
2) Parties' assets at the boundary shall be listed in detailed drawings, diagrams and documentation in the connection agreement.

Article 45. Operating and Maintenance Boundary

Unless otherwise agreed the party that owns an asset shall be responsible for investing, constructing, testing, operating and maintaining all assets that it owns according to the applicable law or rules.

Article 46. General Requirements

1) The relevant TNO must connect a user when the power network/apparatus or power plants of a user seeking connection to the transmission network are compliant with an approved Power Master Plan.

2) The relevant TNO and user must enter into a connection agreement which defines the commercial and technical terms for connection, including but not limited to:

   a) The technical description of the connection;

   b) The commercial terms for such connection, where such terms are in compliance with approved transmission tariffs; and

   c) An agreed time for completion of the connection.

3) Such connection agreement may contain provision for application of reasonable financial penalties where the relevant TNO fails to provide the connection within the agreed time, provided such penalties represent a reasonable pre-estimate of actual losses the user would face due to such delays.

4) For clarity it is noted that if a user's connection requirement was not stated in the Power Master Plan, and if possible, Users may request EWRC for modification of the approved Power Master Plan.

5) Where the appropriate modification of the Power Master Plan has been approved in accordance with the relevant procedures, as issued from time to time by EWRC, then the relevant TNO may connect the user, provided the user agrees to pay for costs arising directly from the proposed connection.

6) The user seeking connection shall undertake to build and operate their power network in compliance with this Grid Code and other current relating rules, standards, procedures and regulations.

7) Before and after connecting to the transmission network, Users must comply with Controlling and Supervising Flicker Emission and Harmonic Emission of user's equipment connected to the transmission network as specified in this Grid Code.

8) TNO shall have the right to reject a Connection Application or to disconnect a power network of a user from their network only if there are evidences on violations of this Grid Code or other current safety and technical regulations by the user and, after following the dispute resolution procedures in Chapter XVII, and EWRC agree that disconnection is appropriate.

9) For each connection point, the user is responsible to provide TNO electrical single line diagram, equipment layout, protection, control, metering and automation systems and other related drawings.

10) The electrical single line diagram shall include all the high voltage equipment at the connection site and shall describe the link between the transmission network and the user's network. The equipment shall be described by standard symbols and signs and shall be numbered by corresponding dispatching center. To avoid misunderstanding, the user's electrical lines and substations shall be named under agreement with TNO.

11) Where a user is seeking modifications on their apparatuses/plants, which may affect the equipment on connection site, the user must obtain approval of the TNO before

implementation of the modifications. That modification then must be updated in the relating documentation of the connection point, including updating and publication of appropriate single line diagrams.

Section f. Technical Requirements for Connected Equipment

Article 47. General Requirements on the User's Equipment

1) Connected equipment must be equipped with circuit breakers and associated protection and control systems which are able to close/open the maximum short circuit current expected at the connection point within the next 10 years.
2) All other equipment directly connected to the connection point must also be capable of withstanding the maximum short circuit current expected at the connection point within the next 10 years.
3) The TNOs must annually advise the maximum short circuit current that may occur at each connection point within the next 5 years, and within the next 10 years. This shall be calculated regarding power system development potential within the next 5 and 10 years. Such short circuit current expectations must be consistent with the TNO obligations under Article 25.
4) For generators, the circuit breaker to be used for connection switching must be equipped with synchro-check system and disconnectors to ensure safety, unless otherwise agreed with the relevant TNO.

Article 48. Requirement on Protection System

1) The TNOs and users are responsible for designing, installing and testing protection system in their own networks so that they comply with the requirements on speed, sensitivity and selectivity. The zone protection and actual arrangement of protection system for TNO and user’s generating units, transformers, bus-bars and transmission lines must comply with this Grid Code and any other current standards and regulations.
2) The coordination among protections at connection point must be agreed between SO, the TNOs and the users.
3) The settings of the protection system of both the TNOs and the users, relating to connection point, must strictly follow the values approved and issued by the SO.
4) Fault clearance time by main protection system on the user's network must not exceed the values specified in Article 25 for the corresponding voltage level.
5) The electrical lines connecting the user's network to the transmission network, and the transmission network itself, must be equipped with protection system according to the latest version of such standards published by the TNOs from time to time.
6) Where users protection equipment is required to communicate with the TNO’s protection equipment it must meet the communications interface requirements specified by that TNO.

7) All generators that are connected to the transmission network shall provide protection against loss of excitation on the generating unit, and against pole slipping on the generating unit.

8) All circuit breakers connecting to connection point must be equipped with breaker failure protection. In the event that the protection system fails to interrupt fault current within fault current interruption time, the circuit breaker failure protection shall be capable of initiating tripping of all the necessary electrically adjacent circuit breakers so as to interrupt the fault current within the next 60ms.

9) In these circumstances, for faults on the user's network, the user's protection may be allowed to trip necessary circuit breakers on TNO's network, subject to the consensus of the TNOs and SO, and it must be described in the connection agreement.

10) The user and TNOs shall install auto-reclosing facilities in their 66 kV network and above if it is required by the SO.

11) The target performance for the TNOs and the user's protection system Dependability Index shall not be less than 99.98%.

Article 49. Requirement on Data/Information System

1) Unless user and SO have another agreement, user shall provide appropriate data/information devices to ensure the uninterrupted communication and data exchange, up to the agreed interface points with the relevant TNO provided communications channels in normal and contingency system conditions.

2) The SO shall, from time to time, advise the user of the required data, communication protocol, and interface.

3) SO is responsible for coordinating with users in commissioning, checking and integrating user's data/information system into existing SO's data/information system.

4) The relevant TNO is responsible for provision of appropriate communications channels.

5) Requirement on data/information system shall be clearly described in the connection agreement and updated documentation.

Article 50. SCADA Equipment Requirements

1) The user is responsible for installing, testing, commissioning and integrating SCADA equipment in the user's network to SCADA/EMS system of the SO.

2) Based on the particular case, the user may use remote terminal unit (RTU) or gateways of DCS.

3) The user's Data acquisition and direct transmitting equipment shall be appropriate to requirements of SCADA/EMS System connection procedure and technical requirements specified by the SO.

4) In cases user's SCADA/EMS changed after two parties reach the agreement, the user shall be responsible for advising the SO of those changes.

5) Integration process of the user's data acquisition and transmitting equipment to the existing SCADA/EMS system of the SO is that each Party shall carry out necessary works in its own system, but the user shall bear full responsibility for successful integration.

6) Except it has different agreement with the SO, any user's generating station or off take substation with nominal total injection or off take power is 50MW or below must be equipped with duplicate Distribution Control Systems (DCSs) or RTUs which directly and simultaneously communicate with the SCADA/EMS System of the SO. Where the nominal total injection or off take power is greater than 50MW the generating station of off take substation must be equipped with duplicate Distribution Control Systems (DCSs) which directly and simultaneously communicate with the SCADA/EMS system of the SO.

7) The list of data to be transmitted to SCADA/EMS system shall be agreed between the user and the SO and shall be specified in connection agreement. This list shall include the following data as minimum:

   a) Status data (digital inputs);

      i) Generation unit (On/Off) (if available);

      ii) Generator circuit breaker (Open/close/undefined) (if available);

      iii) Circuit breaker in switchyard (open/close/undefined);

      iv) Disconnector (open/close);

      v) Earth switch (open/close) (if available)

      vi) Position of tap changer;

   b) Operation data (analog inputs);

      i) Bus-bar voltage (V);

      ii) Active and reactive power of incoming and outgoing feeders (W/VAr) (if available);

      iii) Generating outputs (W/VAr);

      iv) Frequency (Hz);

      v) Current (A);

   c) Accumulator inputs;

      i) Generation outputs (Wh, VArh) (if available);

      ii) Energy transmitted in incoming and outgoing feeders (Wh/VArh);

   d) Control Outputs;

      i) Circuit breaker for incomings and bus section in MV switchyard (open/close);

      ii) Feeder Circuit breaker (open/close);

      iii) Motorized disconnector (open/close) for incomers and bus sections;

      iv) Couplers on MV switchgear;

v) Position of tap changer; and

e) Any other important alarm signals specified by the SO.

8) Other requirements of data acquisition and transmitting equipment (if necessary) shall be clearly described in the connection agreement.

Article 51. Active and Reactive Power Control

1) All generating unit shall be capable of supplying rated power (MW) at any point between the limits 0.9 power factor lagging and 0.9 power factor leading at the generating unit's terminal in accordance with the Generating Unit's Reactive Power Capability Curve.

2) Each asynchronous generating unit shall be compensated by shunt capacitors so as to meet power factor at the connection point between the limit stipulated in item (1) above.

3) Each generator shall be capable of contributing to frequency and voltage control by continuous regulation of active power and reactive power.

4) The active power output under steady state conditions of any generating unit directly connected to the national network shall be fully available and not be affected by voltage changes at connection point in the normal operating range specified in Article 32.

   Each generating unit shall be capable of continuously supplying its rated active power output within the system frequency range of 48.9 to 51.5 Hz. Any decrease of power output occurring in the frequency of 48.9 to 47 Hz shall not be more than the required proportionate value of the system frequency decay in accordance with frequency regulation characteristics of the generating unit.

5) Each hydro generating unit having rated output power above 2MW will at all times ensure that, while connected, its assets contribute to supporting frequency by remaining synchronized:

   a) For at least 5 seconds when the frequency is 52.0Hz;

   b) For at least 20 seconds when the frequency is 51.5Hz

   c) For at least 120 seconds when the frequency is 51.0Hz

   d) At all times when the frequency is above 47.5 Hz and below 50.5Hz;

   e) For at least 120 seconds when the frequency is 47.5 Hz;

   f) For at least 20 seconds when the frequency is 47.3 Hz;

   g) For at least 5 seconds when the frequency is 47.1 Hz;

   h) For at least 0.1 seconds when the frequency is 47.0 Hz; and

   i) At any frequencies between those specified in above for times derived by linear interpolation.

   j) Where the inherent characteristics and design of its generating unit are such that it is reasonably able to operate beyond the above requirements, a generator will declare such capabilities to the SO.

6) Each thermal generating unit having rated output power above 2MW will at all times ensure that, while connected, its assets contribute to supporting frequency by remaining synchronized:
   a) For at least 5 seconds when the frequency is 52.0Hz;
   b) For at least 20 seconds when the frequency is 51.5Hz
   c) For at least 120 seconds when the frequency is 51.0Hz
   d) At all times when the frequency is above 49.5 Hertz and below 50.5Hz;
   e) For at least 120 seconds when the frequency is 49.0 Hertz;
   f) For at least 20 seconds when the frequency is 48.5 Hertz;
   g) For at least 5 seconds when the frequency is 48.0 Hertz;
   h) At any frequencies between those specified in above for times derived by linear interpolation.
   i) Where the inherent characteristics and design of its generating unit are such that it is reasonably able to operate beyond the above requirements, a generator will declare such capabilities to the SO.
7) All generating units shall be capable of withstanding the voltage unbalance as specified in Article 24.
8) All generating units shall be capable of withstanding the negative and zero sequence current occurred in the Transmission network under phase-to-phase and phase-to-ground short circuit conditions which take place near to the generating unit, and it is at least for the time until the faults have been cleared by back-up protection.
9) Each generating unit and the generating station in which it is located shall be capable of continuous uninterrupted operation during the occurrence of the following:
   a) Over-speed up to 4%;
   b) Unbalanced load from 5% to 10%;
   c) Exciter response ratio more than 0.5%; and
   d) Negative sequence current less than 5%.

Article 52. Excitation Systems

1) The excitation system of a generating unit must ensure that the generating unit is capable of operating within the power factor range as specified in item 1) of Article 51.
2) Each generating unit having rated power output above 2MW must be fitted with a continuously acting automatic voltage regulator (AVR) to provide constant terminal voltage over the entire operating range, with accuracy not less than ±0.5% of rated voltage.
3) AVRs must compensate for any drops in the voltage of the Unit Transformer as well as provide a stable distribution of reactive power between the synchronous generating units connected to a common bus-bar.

4) AVRs must provide for limitation of the following:
   a) Minimum excitation current;
   b) Rotor maximum current; and
   c) Stator maximum current.
5) At a generating unit terminal voltage within the range of 80% to 120% of the nominal voltage and at a frequency range of 47 Hz to 52 Hz, the excitation system must provide increase (forcing) in the excitation current and voltage as a factor of nominal load as follows:
   a) Hydro generating units above 2 MW: min. factor 1.8 - min. time 20s; and
   b) Thermal generating units above 2 MW: min. factor 2.0 – min. time 30s.
6) Rate of excitation voltage change shall not be less than 2.0p.u/s to nominal excitation voltage at nominal output.
7) In some cases, TNOs and SO are able to request Users equip Power System Stabilization (PSS) to improve the capacity of stabilizing network.
8) The performance requirements for automatic excitation control, including power system stabilizer (PSS) if included shall be specified in the connection agreement.

Article 53. Speed Governing Systems

1) All generating units must provide primary frequency control during operation.
2) All generating units above 2MW shall be fitted with a fast acting speed governing system to provide frequency response under normal operational conditions. The governor shall be capable of accepting raise and lower signals or set-points from dispatching center's SCADA/EMS system unless this requirement is waived by the SO.
3) All generating units above 2MW shall be fitted with a governor capable of an overall governor speed droop characteristics of 5% or less.
4) Turbine automatic speed control system must provide for limitation and protection against over-speed within a range as follows:
   a) For steam turbines: 104% to 112% of their nominal value;
   b) For hydro, diesel and gas turbines: 104% to 130% of their nominal value; and
   c) Where a generating unit becomes isolated from the rest of the power system but still supplying customers, the speed governor shall also be able to control island frequency.

Article 54. Black Start

At a number of strategically located generating stations, as requirement from the SO, the black start capability is mandatory and it shall be stated in the connection agreement.

Article 55. Additional Generator Protection Requirements

In addition to requirements stipulated in Article 48, user's Generator Protection must meet the following requirements:

a) Each generating unit shall be equipped with precision automatic synchronizing systems;

b) The user's generating units shall be equipped with loss of excitation protection and pole-slipping protection; and

c) For each transmission line of 66 kV and above connecting a generating station or generating unit to transmission network, there must be two (2) independent telecommunication links to use for protection purpose. The time for signal transfer between two (2) ends of the line shall not be longer than 20ms.

Article 56. Neutral Grounding of Generating Unit Transformer

At 66 kV and above, the higher voltage winding of the transformer of a generating unit shall be star-connected with the star point suitable for connection to ground.

Article 57. Power Factor of Demand Users

1) In normal operation, the DCs and DCCs shall ensure power factor, cos φ, at the connection point not less than 0.9.

2) The user is required to provide compensator parameters for relevant TNO as following:

   a) Rated reactive power and controlled range (if available);

   b) Principle and performance of control system; and

   c) Connection point to DCs and DCCs network.

Article 58. Demand Fluctuation

Change rate per minute of the user's power demand shall not be over than 10% of maximum demand.

Article 59. Neutral Grounding of User's Transformer

1) At 161 kV and above, the higher voltage winding of 3-phase and 1-phase transformer shall be star-connected with the star point suitable for connection to ground.

2) The grounding and lower voltage winding arrangement shall be such as to ensure that the ground fault factor shall not exceed the value specified in Article 39.

Article 60. Under Frequency Automatic Load Shedding Systems

1) The user has responsibility to install equipment, make arrangements that will facilitate under frequency automatic load shedding of loads associated in the user's network as requirement of SO.
2) Under Frequency Automatic Load Shedding system shall be designed in conformity with following dependability requirements:
   a) Overall dependability of the entire Automatic Load Shedding system shall not be lower than 96%;
   b) Failure to trip at any one particular load shedding point shall not harm the overall operation of the Under Frequency Automatic Load Shedding system;
   c) Load shedding sequence and corresponding amount of load to be shed shall strictly follow the settings given by the SO and shall not be changed in any case without permission from the SO; and
   d) The under frequency relays shall be suitable for operation from a nominal 110/220V DC input supplied from DC system of substation or 100/110V AC input directly supplied from voltage transformer at busbar, to which the feeder supplying energy to the load is connected.
3) The under frequency relays to be used in the Automatic Under Frequency Load Shedding system shall be fully digital with the following characteristics:
   a) Frequency setting range: 47 to 52 Hz in steps of 0.1Hz;
   b) Adjustable time delay: 0 to 99 s in steps of 0.01s;
   c) Rate of frequency setting range: 0 to 9.9 Hz/s in steps of 0.1Hz/s;
   d) Operating time delay: less than 0.1s;
   e) Voltage lock out: selectable within 55% to 90% of rated voltage;
   f) Facility stages: 4 stages on frequency deviation and 2 stages on frequency change rate; and
   g) Output contacts: minimum of three output contacts per stage.
4) Once the frequency has recovered, the reconnection sequence of loads which has been shed by operation of under frequency automatic load shedding system shall strictly follow instructions from the SO.

Article 61. Metering

Measuring equipment shall be as specified in Chapter X.

Section g. Connection Procedure

Article 62. Connection Agreement Procedures

1) The user proposing a new connection point or any modification at the existing connection point must complete and submit Connection Application to relevant TNO and SO in the forms of Appendix 3.

2) Any proposed new connection point must have a load factor of not less than 40%. Data to support this requirement shall be included in the Connection Application and the requirement shall be included in the Connection Agreement.

3) The Connection Application shall indicate the technical documents of proposed equipment or any modification proposal at current connection point, proposing time to finish project and technical/economic impact assessment of connection between user's equipment and transmission network without constraints of transmission line/transformer capacity and additional cost.

4) Upon receipt of the Connection Application from the user, the following shall be carried out by relevant TNO and SO:

   a) Reviewing the requirements related to proposed connection equipment;

   b) Investigating impacts of acceptance the user's system on transmission network (of all TNOs), including load capability of the existing transmission lines and substations. Any cost or any expense arising from acceptance the user's system to relevant TNO's network shall be estimated;

   c) Negotiate and come to agreement with user concerning:

      i) Cost of connection.

      ii) Voltage for connection and location of connection;

      iii) Detailed technical requirements of the connection including:

         (1) Configuration of all relevant TNO and user assets;

         (2) Protection equipment, settings and co-ordination, as advised by SO;

      iv) Testing commissioning and energizing procedures; and

      v) Processes for determining compliance with all relevant codes and rules.

   d) Once the technical design of the connection point has been agreed then the relevant TNO shall prepare a draft of connection agreement in accordance with the standard laid out in Appendix 4; and

   e) Send the draft of connection agreement to the user.

5) While considering the Connection Application, the user may be required to supply additional information necessary to evaluate in more detail the technical and economic aspects relating to Connection Application by relevant TNO, or SO.

6) The connection agreement between relevant TNO and the user shall only be officially signed when the relevant TNO, SO and user have agreed on all relating matters in writing.

Article 63. Timescales

The outline timescales for the connection procedures are as follows:

Table 10: The maximum time of each stage in connection procedure:

Phase	**Time (duration)**	**By Whom**
Submit formal Connection Application		The user
Review Connection Application, Prepare and Deliver the Draft of Connection Agreement	+ 3 months	TNO and SO
Review the Draft of Connection Agreement	+ 2 months	The user and EWRC
Sign Connection Agreement	+ 1 month	The user and TNO

Article 64. Connection Implementation

The user's system shall only be connected to the national network when all involving matters described Section h of this Chapter are fulfilled.

Section h. Inspection, Testing and Commissioning

Article 65. Access

Relevant TNO and the user have the right to access all equipment at the Connection Site during the time of construction and erection, modifications, commission, operation, testing and maintenance.

Article 66. Preparation Before Energizing

1) By the intended date of energizing of connection point, the user must provide the authorized relevant TNO two sets (2) of the following document (in English and copy from original document endorsed by the user):
   a) The Approved Design and Modification (if applied) from Inception Design, including description, single line diagram, system layout, protection and control configuration diagram, others related and technical specifications of main electrical equipment;
   b) Manual books/Handbook/Operation Guide book from Manufacturers;
   c) Document showing that the construction and erection plant, transmission line, substations are in compliance with the Law, and applicable standards applied in Sierra Leone;
   d) Document showing that facilities, plant, transmission line, substation are in compliance with this Grid Code; and
   e) Document/Certificates or analysis results showing that the user's equipment and system do not cause any negative effect on Transmission network.

2) Time for providing this documentation is as follows unless otherwise agreed:
   a) At least three (3) months prior to the intended date of the first commissioning of generating station(s); and
   b) At least two (2) month prior to the intended date of the first commissioning operation line(s), substation(s).
3) The TNO shall transfer one set (1) of document specified in item 1) above to the SO, and liaise with the SO over developing an agreed commissioning plan.
4) Within 15 days after receiving all document determined by 1) above, the TNO and SO shall provide the Operating Unit of connection user with the following document:
   a) Numbering diagram of equipment, as advised by SO;
   b) Requirements for receipt of dispatch instructions, as advised by SO;
   c) Relay protection settings, as advised by SO;
   d) Start up plan, as jointly advised by SO and TNO;
   e) Testing and commissioning equipment requirements, as jointly advised;
   f) Requirement of telecommunication system with SO, as advised by SO;
   g) SCADA information requirements, as advised by the SO;
   h) Current National Dispatching Rules, as advised by SO;
   i) Switching and emergency procedures, as jointly determined by TNO and SO; and
   j) List of related persons and operators enclosed by telephone, email address and fax number, as jointly advised by SO and TNO.
5) At least 10 days prior to the actual date of energizing of connection point, the user is required to obtain agreement with the TNO and SO on the each following:
   a) Commissioning Schedules;
   b) Asset boundary and responsibilities of each partner for management of equipment at connection point;
   c) Details of Safety Rules in accordance to equipment management boundary; and
   d) List of Operators of each Partner including full name, position, responsibilities, telephone and fax numbers.

Article 67. Connection Point Inspection

1) After accomplishment of works involving connection point, the user shall co-ordinate, actively propose and agree Inspection Schedule with the relevant TNO, and SO.
2) The TNO, the SO and the user shall agree the schedule of inspection of connection point, inspect technical standard and relevant test certificate by inspection day.
3) Whenever the TNO or SO notifies the user that the current status of connection point or any equipment of the user do not meet conditions for energizing, the user shall

complete necessary adjustments, modifications and agree the next inspection schedule with the TNO and SO.

4) During inspection, the user shall prove that equipment in its own system or equipment involving to the connection point are in compliance with current technical standard, procedures and regulations.

5) TNO, in conjunction with the SO, shall issue Certificate of Acceptance if connection point meets all safety requirements and is ready to energize.

Article 68. Connection Point Energizing

1) Upon receipt of Certificate of Acceptance and completion of the necessary legal formalities, the user shall send the Application for Energizing the Connection to the relevant TNO to agree an actual time of energizing.

2) When the Certificate of Acceptance and Application for Energizing Connection have been completed, the TNO shall agree an actual energized time with the SO and inform this to the user.

3) Connection point shall be energized at a date agreed between the TNO, SO and the user.

4) Notwithstanding the above technical energizing procedures, the connection point shall not enter commercial operation until such time as agreed with the EWRC.

Article 69. Commissioning.

1) During commissioning, the user, the relevant TNO and the SO shall assign adequate personnel to meet the requirements of the agreed commissioning plan. List of these persons attached by phone and fax number shall be agreed between all parties.

2) Duration of commissioning shall comply with the current rules and manufacturer's instruction.

3) During commissioning, the user shall closely coordinate with the TNO and SO to minimize impacts of new connection on safe operation, power quality of the whole system and normal operation of other equipment.

4) At the end of commissioning, the user shall certify the actual technical specifications of equipment, lines, substations and generating units. When the user's equipment is failing to meet the technical standards, operation rules of TNO and technical specifications of generating station registered in the connection agreement, TNO has the right to temporarily disconnect the user from transmission network and to request adjustments from the user.

5) The user's network and equipment shall be re - energized when Certificate of Acceptance is re-issued and all user's generating units have met the technical standards, applicable procedures and complied with terms and conditions in the connection agreement.

Article 70. Inspections

1) During operation, the relevant TNO and SO have the right to request the inspection and testing equipment in the user's network to:

   a) Confirm compliance in accordance with technical standards, current procedures and rules of the equipment in the user's network and connection site;

   b) Certify that operation conditions of the equipment in the user's network are in compliance with articles in the connection agreement between TNO and the user;

   c) Assess impacts of the user's network on safe operation of TNO's system; and

   d) Determine the technical specifications of generating units and network of the user for simulation purpose in studies.

2) All the costs for inspection and testing, if not defined in the connection agreement, are as below:

   a) If it is shown that the user's equipment do not comply with technical standards, current procedures and rules or specifications provided by the user much differ from actual specifications, the user shall bear all the inspection and testing costs; and

   b) Otherwise, TNO shall bear these costs.

3) At least 15 days before the inspection date of the user's equipment and network, TNO shall notify the user the time and list of people attending the inspection. The user shall ensure all conditions in their equipment so that the TNO can fluently perform its works.

4) During inspection, TNO has the right to install supervision and testing equipment in the user's network and equipment and keep them operating. These installations shall not influence efficiency and safe operation of network and equipment.

5) In operation, if any technical problem that may cause negative effects to safe operation of system is discovered, the TNO shall advise the user immediately. The notification shall include a date by which the technical problem must be rectified. If the technical problem has not been rectified within the required time, or the problem is so significant as to materially impact the TNO or SO's ability to meet their performance targets, as per Chapter III, then the TNO has the right to disconnect the connection and notify the user. Upon receipt of Disconnection Notification issued by the TNO, the user shall follow the provisions of Article 69 before applying for reconnection, within a reasonable timeframe.

6) The SO has the right to test the connected equipment or the whole connected installation at any time to determine one or more operation characteristics registered by the user, but testing for any one unit of equipment shall not be more than 3 times per year, except:

   a) Test results show that one or more operation characteristic(s) differ from that registered by the user;

   b) There is dispute on estimation operation characteristics of the equipment;

   c) Testing at the user's request; and

   d) Testing at fuel transfer.

7) The user has the right to test its own equipment to re-confirm operation characteristics after repairing, improvement or re- installation. Testing schedule shall be agreed with SO.

Article 71. Information Exchange

1) Prior to the start of the commissioning and as required thereafter the TNOs and SO will jointly issue a National Power System Operating Procedure. This shall lay out the necessary information exchange procedures for safe and effective operation of the national power system. As a minimum it will cover the process by which:
   a) The SO and TNO shall, as soon as possible, notify the Users of actions or faults in the part of network that may influence normal operation of the user.
   b) The user shall, as soon as possible, notify the TNOs and the SO of any actions or faults that may influence safe, stable operation of network and, if required, the user shall submit all related data to the TNOs and the SO for fault analysis.

2) All users shall comply with this National Power System Operating Procedure.

Article 72. Data Archiving and Exchange

The user shall maintain all the data related to operation, repairing, maintenance and faults in all elements of its own network in period of 3 years. When required by the TNO, the user shall submit necessary data involving to faults in its own network and equipment. When the user proposes modifications, upgrading connection equipment, or installing new equipment that may affect efficiency and operation regime of the whole network, the user shall notify and agree the change with TNO. Details of changes shall be updated in connection agreement. If the Modification Proposal from the user has not been approved, relevant TNO will notify the user of the required technical specifications of new equipment.

Section i. Disconnection and Reconnection

Article 73. Disconnection Classifications

Cases of disconnection shall be classified as below:

a) Voluntary Disconnection; or

b) Involuntary Disconnection.

Article 74. Voluntary Disconnection

1) Permanent disconnections at the user’s request and responsibilities of all parties shall be specified in detail in the connection agreement.

2) According to terms in the connection agreement, the user could request permanently disconnection of his own equipment, providing that the user shall bear all disconnection cost and inform TNO, and SO.

3) User shall notify relevant TNO and SO of the disconnection day at least 6 months prior.
4) Subject to relevant TNO agreement a user may temporarily disconnect his own equipment.

Article 75. Involuntary Disconnection

A TNO has the right to disconnect the user's equipment from National network only in following cases:

a) Disconnection due to EWRC's orders;
b) Disconnection to ensure safe and reliable operation of system and/or safety for employees and equipment in emergency cases;
c) As required by the laws relating to electricity or other related legislation;
d) As required by the connection agreement; or
e) Disconnection when serious severe fault occurred and lead to the need to isolate user's equipment, or when automatic under frequency load shedding relay operate.

Article 76. Reconnection

The relevant TNO must reconnect the user to transmission network once the reasons and consequences of disconnection have been solved.

Chapter V. **Network Planning Principles**

Article 77. Principles of Annual Transmission Expansion Plan

1) EWRC is responsible for preparation of a National Transmission Expansion Plan which:
   a) Looks forward at least 10 years as a long term plan and 5 years for a midterm review;
   b) Account for any WAPP requirements;
   c) Allocate responsibilities to (and between) TNO(s) for transmission development; and
   d) Such National Transmission Expansion Plan form an input to the EWRC tariff setting process.
2) Each TNO is responsible for investment to develop their transmission network to:
   a) Support the current approved National Transmission Expansion Plan (including any WAPP requirements), regional power development plan(s), and any current connection contracts; and
   b) Meet the network performance criteria in Article 22 to Article 33.
3) Prior to the start of the SLEM, and as required by EWRC thereafter, each TNO shall prepare a network planning criteria and methodology, to meet its investment responsibilities, for approval by EWRC.
4) This network planning criteria and methodology should include as a minimum:
   a) A process for the TNO to identify and resolve any inconsistencies between the WAPP requirements, the National Transmission Expansion Plan and the regional power development plan, where such inconsistencies impact transmission network planning;
   b) A process for the TNO to demonstrate how it plans to meet the requirements of item 1) above. As a minimum this must include:
      i) A set of input planning assumptions consistent with item a) above;
      ii) Load flow studies to evaluate the behaviour of the Transmission Network under forecast maximum and minimum load conditions and study the impact of any proposed new connections;
      iii) Short circuit studies to evaluate the effect on the Transmission Network of any proposed new connections or interconnections. These studies will identify any situation where the fault current standard in Article 25 may be exceeded and consider the least total cost method of addressing any such issues;
      iv) Transient stability studies to evaluate the impact on the Transmission Network of new connections or interconnections on the ability to reach a stable operating point following a transient disturbance;

v) Steady state stability studies to evaluate the impact on the Transmission Network of new connections on the ability to maintain steady state stability following disturbance or if any dynamic stability problems may arise;

vi) Voltage stability studies to evaluate the impact on Transmission Network of new connections or interconnections on the ability to avoid voltage collapse; and

vii) Electromagnetic transient analysis to determine whether any very short duration current and voltage transients may affect equipment insulation.

viii) Reliability analysis to determine the probability of loss of load and unserved energy;

ix) Contingency analysis; and

x) Any other analysis consistent with good electricity industry practice for network planning.

c) A process for the TNO to consider whether an adjustment of the network performance criteria in Article 22 to Article 27 may allow a lower overall cost solution as a whole; and

d) A process for the TNO to consult the SO and users in developing the network development plan.

5) EWRC shall review the proposed network planning criteria and methodology and either approve, or recommend required changes;

6) Each TNO shall, if necessary revise, the network planning criteria and methodology until it meets EWRC's satisfaction;

7) Once satisfied with the network planning criteria and methodology, the EWRC shall approve it.

8) Each TNO must only use an approved network planning criteria and methodology in preparing any transmission expansion plan.

9) By 1st January of each year, each TNO shall produce an annual transmission expansion plan (TEP).

10) Each TEP must be consistent with the National Transmission Expansion Plan and the Power Master Plan.

11) Each TEP will cover a period of 5 years from the date of submission.

12) Each TEP shall be submitted to EWRC for approval.

Article 78. Contents of Annual TEP

1) Each TEP must include, as a minimum, the following main contents, for the period covered by the TEP:

a) A transmission network expansion planning methodology;

b) Evaluation of the current technical situation of transmission network;

c) A forecast of demand and impact on existing transmission capacity;

d) A list of generation projects to be connected, and details of the connection point, and connection contract for each such generation project;

e) A list of new demand connections proposed, and details of the connection point and connection contract for each such new demand connection;

f) A list of any new connections proposed, that are not included in the annual list, and details of the connection point and connection contract for such new connections;

g) Calculation of the system's power distribution and expected peak and average power flows, at steady state in dry and wet season;

h) Analysis of the system's steady and dynamic stability;

i) Calculation of the short circuit at all 225 kV, 161 kV, 66 kV buses and those 33 kV and 11 kV buses that are directly connected to higher voltage buses;

j) Analysis defining the transmission network's compensative reactive power requirements in the planed period;

k) Analysis of the areas the TNO considers black start capability will be required;

l) Analysis of whether the transmission network can continue to meet the network performance criteria in Article 22 to Article 33;

m) Analysis of the least cost investment required to:

   i) Support the current approved National Transmission Expansion Plan, Regional Power Development Plan, and any current connection contracts; and

   ii) Meet the network performance criteria in Article 22 to Article 33.

n) A proposed development plan to meet the above requirements over the planning period; and

o) A proposed expenditure plan for the next financial year consistent with the proposed development plan.

2) For the avoidance of doubt, all of the assumptions and calculations in item 1) above, except for item f), must be consistent with the annual list.

Article 79. Responsibilities of Generators, DCs, DCCs and SO

1) Users are responsible for entering into contracts with the relevant TNO for any new connection they require as per the provisions of Article 62.

2) At least 3 months prior to the due date for the annual TEP, each TNO will provide the SO and all users with a list of information required from them, and due date for this information, to assist the TNO in their process of preparing the TEP. For avoidance of doubt the dates for provision of demand data from DCs and DCCs shall be consistent with the requirements of Article 134.

3) Notwithstanding item 2) above parties to this Grid Code must provide the TNOs and SO with the following information as a minimum:

a) Generators:

   i) A list of all new generating stations they expect to commission within the next 5 years;

   ii) A list of all generating stations they expect to decommission in the next 5 years

   iii) The current expected date for commissioning or decommissioning of such generating stations;

   iv) The key technical characteristics of such generating stations, including their current best estimate of connection data as per Appendix 4, part 3;

   v) The expected point of connection, and expected connection requirements of such generating stations; and

   vi) Any proposed change of existing generating stations expected within the next 5 years, including full details of the expected change.

b) DCs and DCCs:

   i) A list of all new transmission network offtake points they expect to commission within the next 5 years;

   ii) The current expected date for commissioning of such off take points;

   iii) The key technical characteristics and demand data of such offtake points, including their current best estimate of the connection data as per Appendix 4, part 2;

   iv) The expected point of connection, and expected connection requirements of such offtake points;

   v) Any proposed change of existing offtake points expected within the next 5 years, including full details of the expected change.

c) Power pool operator:

   i) A list of all new transmission network injection and offtake points they expect to commission within the next 5 years;

   ii) The current expected date for commissioning of such injection and offtake points;

   iii) The key technical characteristics and demand data of such injection and offtake points, including their current best estimate of the connection data as per Appendix 4, part 2, and part 3;

   iv) The expected point of connection, and expected connection requirements of such injection and offtake points;

   v) Any proposed change of existing injection and offtake points expected within the next 5 years, including full details of the expected change.

d) SO:

   i) Expected demand forecast for the next 5 years, prepared in accordance with Article 134;

   ii) Expected ancillary service requirements for the next 5 years;

iii) Expected requirements for secure power system operation for next 5 years, including but not limited to the expected impact of such requirements on transmission network operating capability; and

iv) Expected annual generation patterns to meet expected load for next 5 years.

4) All users must comply with any reasonable request for information from the TNO under this article.

Article 80. Approval of TEP

1) Within 15 days of receipt of a TEP, the EWRC shall advise the relevant TNO whether it considers the proposed TEP to be complete.
2) If EWRC advises that it does not consider a TEP to be complete it shall also advise what additional information it requires before the TEP can be considered sufficient and complete.
3) Within 30 days of receipt of a complete TEP, the EWRC shall either:
   a) Approve the proposed TEP; or
   b) Reject the proposed TEP, providing reasons for the rejection.
4) Where EWRC rejects a TEP, the relevant TNOs must submit a revised TEP with 45 days.
5) Where EWRC receives a revised TEP then the process recommences at step 1) above.

Article 81. Implementation of TEP

Where a TEP is approved by EWRC then the relevant TNO must publish on its website the approved TEP and carry out the investment, rehabilitation, improvement of power transmission equipment in accordance with the approved TEP. The approved TEP forms an input to the EWRC tariff setting process.

Chapter VI. Power System Operation

Section j. Principles of Secure Power System Operation

Article 82. Principles of Operation

1) The SO is responsible for the overall safe and efficient operation of the power system.
2) Generators, TNOs, and power pool operator(s) shall comply with dispatching schedule and dispatching instructions issued by SO to carry out operation of the generating stations, the transmission networks, and power pool(s) (to the extent it impacts on Sierra Leone power system operation).
3) Outage planning for all connected parties will be coordinated by the SO.
4) No party may carry out a planned outage unless it is approved by the SO.
5) Unplanned outages are only permitted for a bona fide physical reason.
6) Operating modes of the power system are defined as follows:
   a) The power system shall be considered in normal operating mode when all of the following conditions exist:
      i) The power system supply and demand are in balance;
      ii) The loading levels of all transmission network equipment is below 91% of their continuous rating at ambient temperature of 30°C or below 81% of their continuous rating at ambient temperature of 40°C, according to IEC 60354,
      iii) All other equipment is operating within its specified range;
      iv) System frequency is within the range specified in Article 19 for normal operation,;
      v) System voltage is within the range specified in Article 32 for normal operation;
      vi) The transmission system loading is such that all transmission network equipment are capable of returning to 100% of its continuous rating within 15 minutes of a single contingent fault; and
      vii) Sufficient reserve of all classes is available to ensure the power system is capable of automatically returning the frequency and voltage to within these ranges, and all equipment to its specified operating range, for a single contingent fault, automatically and without load shedding.
   b) The power system shall be considered to be in alert operating mode when any one of the following conditions exist:
      i) Regulation reserve, fast start reserve, or spinning reserve levels are below the operating levels set for them by the SO;
      ii) The loading levels of any transmission network equipment is above 91% of their continuous rating at ambient temperature of 30°C or above 81% of their continuous rating at ambient temperature of 40°C, according to IEC 60354 ;

iii) The loading levels of any transmission network equipment would remain above 100% of its continuous rating for more than 15 minutes for a single contingent fault automatically and without load shedding;

iv) A weather disturbance has entered the area of responsibility which may affect power system security; or

v) Law and Order issues exist which may pose a threat to power system security.

c) The power system shall be considered to be in an emergency operating mode when any one of the following conditions exist:

i) System frequency is outside the range specified in Article 19 for normal operation but within the range specified for a single contingent event;

ii) System voltage is outside the range specified in Article 32 for normal operation but within the range specified for a single contingent event; or

iii) The loading levels of any transmission network equipment or transmission network connected equipment is above its continuous rating.

d) The power system shall be considered to be in extreme operating mode when any one of the following conditions exist:

i) The system frequency is outside the range specified in Article 19 for a single contingent event;

ii) The system voltage is outside the range specified in Article 32 for a single contingent event;

iii) The loading levels of any transmission network equipment or transmission network connected equipment is above 110% of its continuous rating; or

iv) The corrective measures undertaken by the SO when the system was in emergency operating mode failed to maintain system security and resulted in cascade outages, islanding or system voltage collapse.

e) The power system shall be considered in restorative operating mode when generating units, the transmission network and loads are being energized and synchronized to restore the power system to normal state.

7) In operating the power system the SO shall observe the following rules for maintaining the safety and reliability of the power system:

a) In normal state, the power system shall be maintained in normal operating mode;

b) In alert operating mode, the SO shall notify all users of the existence of the alert operating mode and request their assistance in returning the power system to normal operating mode;

c) Immediately following a single contingent event, the power system may operate in the emergency operating mode. In this case, the System Operator will carry out reasonable measures to adjust operating conditions to return to the normal operating mode as soon as possible;

d) Load shedding and power supply interruption shall be carried out only if safety risks exist to people and equipment, or multiple contingent events occur, or when the system is in extreme operating mode;

e) Generated power and consumed power shall be balanced in foreseeable conditions. The automatic load-shedding device shall be suitably arranged in order to meet requirement on restoring power system to the emergency operating mode when a faults happen;

f) Apply constraints on power flow, including where necessary separation of parts of the system, in order to prevent, or avoid, faults from spreading in the power system or cascade failure.

g) Any faulted area of the power system part shall be quickly and safely restored; and

h) Ensure enough power capacity available for starting up from black.

Article 83. Protection of Power System

All protection philosophies shall comply with the Electrical Equipment Standards as issued from time to time by the SO and approved by the EWRC.

Article 84. Stability of the Power System

1) The power system shall be operated to avoid instability including:

   a) Transient instability and dynamic instability, which happens when undying oscillation between parts of power system leading to separation of a normal part of power system for some seconds;

   b) Static instability, which is small undying oscillation because the power system starts operation near limit of instability;

   c) Voltage instability, which is where a small disturbance can lead to damaging voltage swings;

   d) Prolonged instability due to low frequency oscillations (Sub-synchronous resonance) at frequency below the line frequency. Usually due to electrical resonance between series capacitors and line reactances.

2) The SO is responsible for carrying out necessary studies in order to identify stable operation margins of power systems. The SO is to advise the TNOs and Users the information required from them in order for the SO to carry out the necessary studies, and the time frame required for provision of the information. For users this information will include, but not be limited to that listed in Appendix 3. For the TNOs the information will include, but not be limited to that listed in Appendix 4. The TNO and Users are required to provide such information within the time frame required.

3) All parties related to power system operation are responsible for maintaining the power network within limits of stability already identified for each period, coordinating with each other to maintain protection systems to clear faults in a quick, sensitive and selective way.

4) Where necessary the SO shall apply security constraints to the scheduling and dispatch process to ensure stability limits are not exceeded.

5) The generators are responsible for maintaining regulation of working voltage and ensure supplying enough reactive power capacity to the power system throughout the operation period, and not to separate or withdraw generator units from operation when change happens, except in case frequency or voltage exceed permissible limits, which can cause equipment damage and when SO agreed for such separation.

6) Power distributors are responsible for maintaining operation of voltage regulators in their power systems in order to assist voltage of the main power system.

Article 85. Testing and Supervision of Testing

1) Generators are to carry out tests when instructed to do so by the SO. When instructing on testing, the SO shall advise the timing of such tests. During such tests the generator may be required to be removed from normal dispatch and operation.

2) Test on automatic response of generator unit to changes of frequency of power system is carried out during normal operation of power system. In this case, the SO shall inform the generators sixteen (16) hours prior to carrying out the test on their units.

3) Tests are only carried out within working ability of unit in operation characteristics and within time informed for test.

4) Any one test shall not last more than sixty (60) minutes.

5) The SO has right to carry out test on generator units at any time, and test may be for one operation characteristic or combination of operation characteristics but not more than three (3) tests carried out on one generator unit except the following cases:

   a) Test results show that one or more operation characteristics are not similar to what stated by the power generating entity;

   b) When the SO and power generating entity do not agree with each other on appropriate value of generator unit's operation characteristics; or

   c) Test on request of power generating entity.

6) Power generating entity has right to require tests in the following cases:

   a) For checking against operation characteristics of generator unit, which has been adjusted after damage related to unit happened; or

   b) For checking generator unit after installation, major repairs, replacement, modification or reassembly.

7) When making request for testing generator unit, the generating entity shall send written request for testing to the SO with clarification of the following information:

   a) Document of generator unit;

   b) Characteristics of generator unit; and

   c) Values of operation characteristics expected to be changed through testing.

8) Within two (2) working days from receiving request of power generating entity, the SO is responsible for organizing testing. In case such testing has not been held yet, the SO may request operating entity to run generator unit according to the expected changed characteristics.

Article 86. Fault Shooting

1) Prior to the start of the SLEM and periodically, as required thereafter the SO shall develop and publish Fault Clearance Procedures. The procedures shall follow the principles outlined in this article. The procedures will cover the alert, emergency and extreme operating modes as described in Article 82. The SO shall consult all affected parties in developing these procedures. The SO shall submit the procedures to EWRC for approval at least 3 months prior to the scheduled start of the SLEM, or whenever subsequent changes are made to these procedures. Once approved by EWRC the procedures will be considered binding on parties.
2) Cases of power system faults for the extreme operating mode include:
    a) Low frequency load shedding
    b) Associated load shedding
    c) High frequency generation shedding, causing generators to be stopped
    d) Load shedding in the case the lines or generators are cut/isolated in order to avoid cascade power system collapse.
3) During process of solving the above-mentioned faults, the SO has rights to allow the power system operating at frequency and voltage other than specified standards, and carry out measures to restore the power system as soon as possible.
4) Methods of solving faults:
    a) Generation shedding may be carried out as required to restore frequency to within the normal operating range;
    b) Load shedding may be carried out according to each power line route by automatic low frequency load shedding relays, or manual load shedding;
    c) Low frequency relays for automatic load shedding are located in appropriate points in the power system. The SO shall determine installation places, setting values of low frequency relays and instructions for manual load shedding in case of system fault. When fault happens, load is shed at steps: 49.5Hz, 49.35Hz, 49.15Hz, 49.0 Hz, 48.8 Hz, 48.6 Hz, 48.3 Hz, and 47.9 Hz. In the emergency operating mode, the SO has right to dispatch shedding of load at any frequency but must comply with stipulations of fault clearance procedures;
    d) When frequency increases to permissible values, DCs, DCCs, and power pool operators, under SO guidance, are responsible for restoration of shed loads;
    e) The SO has right to intervene in order to prevent consequent cutting-off of generator units, or power transmission lines; and
    f) Those generating units having black start capability, may be appointed by the SO to start up in order to restore the power system. In necessary case, the SO can ask generator to operate one generating unit that is not in compliance with its operation characteristics provided that it ensures safety for staff and equipment. When receiving dispatch instruction to restart from black-out situation, the generator is responsible to immediately restart its generating unit and inform the SO of this. The

SO shall energize appropriate loads and lines in order to ensure that this generating unit is stably re-started, and is synchronized with other generating units.

Article 87. Reduced Security Notices

1) At any point in time when the SO considers there is a significant risk of reduced security of supply, and a risk of emergency load shedding being required within the next 24 hours, the SO shall, as soon as practical after it becomes aware of the situation, issue a reduced security notice to all parties outlining:
   a) The nature of the security risk;
   b) The cause, if known, of the increased security risk;
   c) The likelihood of emergency load shedding being required; and
   d) Those parties and areas likely to be affected by the security risk.
2) Where practical the SO will inform all affected parties prior to initiating emergency load shedding. Such notice shall include:
   a) The sites where electricity supply will be interrupted or shed;
   b) The reason of interrupting or shedding electricity supply;
   c) The time of starting to interrupt or shed electricity supply; and
   d) The time of finishing interrupting or shedding electricity supply.
3) Where it is not practical to provide such advice prior to emergency load shedding the SO will inform parties immediately after initiating emergency shedding of:
   a) The sites where electricity supply was interrupted or shed;
   b) The reason of interrupting or shedding electricity supply;
   c) The time of starting to interrupt or shed electricity supply; and
   d) The time of finishing interrupting or shedding electricity supply.

Article 88. Emergency Load Shedding

1) Where the SO requires load shedding in accordance with the provisions of Article 82, then the SO is responsible to carry out measures to allocate loads including calculation, allocation of used power and electricity or power and electricity to be reduced at DCs, DCCs, power pool operators, and transmission network users, in order to ensure safety and stability of the power system.
2) DC, DCCs, power pool operators and transmission network users are responsible to strictly comply with amount of power capacity and electricity allocated by SO.
3) In cases of emergency, SO has the right to shed a part of the loads of any DCs, DCCs, power pool operators and transmission network users, regardless amount of allocated power capacity and electricity.

Article 89. Reference Time

1) SO is responsible for installation of equipment indicating reference time. The reference time is taken from GPS system. Time is Freetown time.
2) Authorized operating staff of generators, DCs, DCCs, power pool operators and transmission network users are responsible for implementing and setting time following the reference time and shall ensure tolerance within ± 5 milliseconds.
3) The SO shall adjust generation dispatch to maintain electrical time to within ± 5 seconds of reference time.

Section k. Roles in Secure Power System Operation

Article 90. Authority of SO in Power System Operation

The SO has rights:

a) To order the TNOs to carry out operation of direct switching in the transmission network, cutting-off and closing for transmission network institutional, individual users;
b) To check and prove electric equipment protection diagrams of institutions, individuals who have connections to the transmission network in cases where such protection diagrams have effect on protection systems of transmission network;
c) To set up and maintain system of communication and remote control for operation of the power system;
d) To dispatch power pool operators in compliance with stipulations of this chapter to the extent its operation impacts on the Sierra Leone power system;
e) To dispatch operation of generator units in compliance with stipulations of this chapter;
f) To dispatch the operation of distribution networks related to safety and reliability of power system; and
g) To refuse maintenance schedules of generating stations and transmission network except where the non-execution of the maintenance schedules will jeopardise the network.

Article 91. General Responsibilities for Operation

The general responsibilities of parties involved in power system operation are as follows:

1) Each TNO has following responsibilities:
   a) Offering equipment under its control to the SO for dispatch;
   b) Complying with dispatch instructions of the SO;

c) Preparing protection diagrams of transmission network and maintaining proper operation of protective equipment in compliance with protection diagrams;

d) Complying with all procedures, norms on operation of the transmission network;

e) Maintaining transmission network in a safe and reliable state; and

f) Restoring transmission network after serious faults.

2) Power generating entities have the following responsibilities:

a) Maintaining operation of speed regulation and excitation systems in order to supply enough energy and ancillary services as required in the power connection agreement;

b) Complying with dispatch instructions of the SO;

c) Shall not separate generator units from the transmission network during time when there are big fluctuation in the power system, unless power generating entity can prove that if its generator unit is not separated from the transmission network, the equipment will be damaged or that the equipment has been damaged by fault and forced to separate from the transmission network; and

d) Shall provide to the SO the data of plant and operation.

3) Power pool operating agencies feeding into the national power grid have the following responsibilities:

a) Maintaining operation of the overall power pool in order to supply enough energy and ancillary services as required in the power pool interconnection agreement;

b) Complying with dispatch instructions of the SO, to the extent the power pool operation impacts on Sierra Leone power system;

c) Shall not separate the interconnection from the Sierra Leone transmission network during time when there are big fluctuation in the power system, unless power pool operating agency can prove that if its power pool is not separated from the transmission network, the equipment will be damaged or that the equipment has been damaged by fault and forced to separate from the transmission network; and

d) Shall provide to the SO the data of plant and operation

4) DCs and DCCs have the following responsibilities:

a) Complying with dispatch instructions of the SO, or the TNO where the TNO is acting under instruction of the SO;

b) Maintaining operation of power compensation equipment in power distribution network, in order to meet reactive power demands which the Distributor has obligation to supply for the power system; and

c) Maintaining availability of automatic load shedding system in compliance with agreement with the SO.

5) The user who directly connects to the transmission network has following responsibilities:

a) Complying with dispatch instructions of the SO;

b) Following the load curve and ensure power factor as agreed in the Power Purchase Agreement;

c) Maintaining operation of automatic equipment and protection system against fault spreading into the power system: and

d) Maintaining availability of automatic load shedding system in compliance with agreement with the SO.

Article 92. SO Dispatch Obligations

1) The SO is responsible for undertaking security constrained economic dispatch in accordance with the principles outlined in Section j, issuing dispatch instructions, keeping an electronic log of dispatch instructions and monitoring compliance with dispatch instructions.

2) The SO is responsible for monitoring compliance with dispatch instructions and reporting any non-compliance, outside the tolerance band, to EWRC, together with any explanation for the non-compliance as advised by the generator.

3) The SO is to annually submit to EWRC a recommended set of dispatch tolerance bands for all classes of generators. This is to take account of generators fuel source, physical limitations on ability to control generator output, and any relevant locational issues. EWRC will consider such recommendations and publish an approved set of dispatch tolerance bands. For the avoidance of doubt, dispatch tolerance bands for non-dispatchable renewable generators shall take into account the variability of their fuel source and reasonable efforts to forecast these variations in formulating their offer.

Article 93. MO Dispatch Obligations

The MO is responsible for providing the SO with the final energy and ancillary service offers from all generators and power pools participating in the SLEM, at the time specified in Appendix 2. For the avoidance of doubt all generators, including non-dispatchable renewable generators are required to provide generation offers to the MO. Such offers must reflect their best assessment of their ability to generate. In the case of non-dispatchable renewable generation it must represent their best estimate of their expected output.

Article 94. Generator Dispatch Obligations

1) All generators are obliged to advise on their machine capabilities, including generating capacity, start up and stopping times, and ramp rates, to the SO in a form and to a time schedule advised by the SO. Generators will advise the SO as soon as possible of any material change in generator capability that comes to their notice. Such advice will include a description of the reason for the change.

2) All generators that participate in the SLEM are, to within dispatch tolerance bands, obliged to follow dispatch instructions, properly issued by the SO, except where doing so would endanger people or equipment or breach their legal obligations. Generators

are to report to the SO any failures to follow instructions and provide information on why they were unable to do so.

Article 95. Power Pool Dispatch Obligations

1) All power pool operators are obliged to advise on their pool capabilities, including overall interconnecting capacity, start up and stopping times, and ramp rates, to the SO in a form and to a time schedule advised by the SO. Power pool operators will advise the SO as soon as possible of any material change in interconnecting capability that comes to their notice. Such advice will include a description of the reason for the change.
2) All power pool operators that participate in the SLEM are, to within dispatch tolerance bands, obliged to follow dispatch instructions, properly issued by the SO, except where doing so would endanger people or equipment or breach their legal obligations. Power pool operators are to report to the SO any failures to follow instructions and provide information on why they were unable to do so.

Article 96. DC Dispatch Obligations

1) All Distribution Companies must advise the SO of the technical capability of their equipment in a form and to a time schedule advised by the SO. Distribution Companies will advise the SO as soon as possible of any material change in equipment capability that comes to their notice. Such advice will include a description of the reason for the change.
2) All Distribution Companies are, to within dispatch tolerance bands, obliged to follow dispatch instructions, properly issued by the SO, except where doing so would endanger people or equipment or breach their legal obligations.

Article 97. TNO Dispatch Obligations

1) All TNO(s) are to advise on their technical equipment capabilities to the SO in a form and to a schedule advised by the SO. Unless subject to an agreed outage, each TNO is to offer all assets under their control to the SO for dispatch. Each TNO will advise the SO as soon as possible of any material change in equipment capability that comes to their notice. Such advice will include a description of the reason for the change.
2) All TNO(s) are, to within dispatch tolerance bands, obliged to follow dispatch instructions, properly issued by the SO, except where doing so would endanger people or equipment or breach their legal obligations.

Article 98. SO Right to Delegate

Notwithstanding anything else in this Grid Code the SO may delegate parts of its duties to specifically trained TNO staff where such staff are certified by the SO as having adequate general knowledge of the power system. For clarity it is noted that such delegation will in no way reduce or diminish the SO's responsibility under this Grid Code for performance of its duties regardless of whether those duties are performed directly or delegated.

Section I. Ancillary Services Procurement

Article 99. Ancillary Services Procurement Overview

1) As part of its responsibility for maintaining overall real time security of supply the SO needs to ensure certain ancillary services are dispatched in real time. Ancillary services are procured, scheduled and dispatched by the SO.
2) The provision of Spinning Reserve, Regulation, and Reactive Power is mandatory for all generators, except non-dispatchable renewable generators, and power pool operators. These services are paid for on the basis of hourly prices.
3) The SO will procure Fast Start Reserve, Cold Start Reserve, Reliability Must Run and Black Start via long term contracts.
4) Ancillary service prices and the form of contract will be in accordance with a methodology to be published by EWRC from time to time.
5) Ancillary services are settled by the MO under procedures contained in the Market Rules.
6) This section lays out the technical requirements for generators to provide ancillary services, the process by which the SO determines the quantity of ancillary service to be procured, and how they are to be scheduled and dispatched.

Article 100. Ancillary Services Categories and Technical Requirements

The following categories of ancillary service are required for safe and reliable operation of the power system:

a) Spinning Reserve: To provide spinning reserve a generator or power pool operator must be able to ramp up to its full output power, in response to frequency or other automatic signal provided by the SO, within 25 seconds and sustain that output level for at least 30 minutes. All generators and power pool operators are required to provide spinning reserve when requested by the SO.

b) Regulation reserve: To provide regulation reserve a generator, or power pool operator, must be able to vary its output, up or down, in response to small frequency changes in accordance with a droop response curve advised from time to time by the SO. It must be capable of varying its output by more than 5% within 1 second, and be able to sustain that variation for at least 25 seconds. All generators and power pool operators are required to provide regulation reserve when requested by the SO.

c) Fast Start Reserve: To provide fast start reserve a generator, or power pool operator, must be able to ramp up to its full output power within 15 minutes and sustain that output for at least 8 hours.

d) Cold Start Reserve: To provide cold start reserve a generator or power pool operator must be able to ramp up to its full output power within 8 hours and sustain that level of output for at least 1 week.

e) Reliability Must Run Reserve: To provide reliability must run reserve a generator or power pool operator must be capable of ramping up to its full output within 1 hour and sustain that level of output for at least 8 hours.

f) Reactive Power: To provide reactive power a generator or power pool operator must be capable of varying the phase angle of its output in response to a request from the SO. All generators and power pool operators are required to provide reactive power when requested by the SO.

g) Black Start: To provide black start a generator or power pool operator must be capable of starting its generation from cold without any external power supply, and capable of connecting to and supplying the Transmission Network with electricity once started.

Article 101. Principles of Ancillary Services Procurement

1) Prior to the start of the SLEM and at least annually thereafter the SO shall develop and publish a methodology for determining ancillary service procurement requirements. The objective of this methodology, in order of importance, shall be to:

   a) Ensure a prudent energy margin and prudent capacity margin can be maintained throughout the year; and

   b) To achieve these outcomes at least total cost, with the limits of the resources made available to it.

2) The ancillary services determination methodology shall take into account the principles laid out in Article 3.

3) Using this methodology the SO shall procure the ancillary services it anticipates will be required for safe and reliable operation of the power system for the coming year, in accordance with the procurement methodology specified in Article 103.

Article 102. Ancillary Services Requirements Determination Methodology

1) In addition to the objectives laid out in item 1) of Article 100 the ancillary services requirement determination methodology shall take into account the following principles:

   a) Spinning reserve

   Spinning reserve shall be set to cover the net impact of the largest single contingent event.

   b) Regulation reserve

   Regulation reserve shall be set to cover the expected variation in net demand, accounting for any likely change in output from non-dispatchable renewable generators, during the period between dispatch instructions.

   c) Fast Start Reserve

Fast start reserve requirements should be set to cover the difference between the prudent capacity margin standard, identified in accordance with Article 144, and the forecast capacity margin, calculated in accordance with Article 146.

d) Cold Start Reserve

Cold start reserve requirements should be set to cover the difference between the prudent energy margin standard, identified in accordance with Article 144, and the forecast energy margin, calculated in accordance with Article 146.

e) Reliability Must Run (RMR) Reserve

To determine which generators are eligible for reliability must run contracts, and the quantity to be procured the SO shall compare constrained and unconstrained runs of a market simulation model. The market simulation model shall use the same principles and inputs as that used for scheduling and dispatch. The unconstrained model run will use reasonable assumptions about available generator capacity and energy, but without any transmission limits. The constrained run shall be the same as the unconstrained run but will add constraints to represent secure transmission limitations based on the existing transmission network, any changes in the latest TEP, and the SO's normal transmission security policy. Where the constrained model run shows a higher level of dispatch, by a prudent RMR margin, than the unconstrained model run for a generator then that generator shall be eligible for an RMR contract for the additional constrained quantity. The prudent RMR margin to be used in determining which generators are eligible for an RMR contract will be as determined by EWRC from time to time in accordance with Article 103. For the avoidance of doubt RMR procurement costs shall be considered by EWRC in determining the Power Master Plan and the National Transmission Expansion Plan.

f) Black Start

Black start requirements shall be set to ensure sufficient black start capacity is available to restart the system for any credible local or system wide black out. In making such a determination the SO shall divide the transmission network into regions based on credible transmission contingencies that could lead to regional islanding. The SO shall procure two generators with black start capability within each region.

g) No Double Contracting

In determining the required quantity of each class of ancillary service to be procured the SO shall take into account the quantity of other ancillary services already procured and not double contract with any generator or power pool operator.

Article 103. EWRC to Consult TNOs on Prudent RMR Margin

In determining the prudent RMR margin to be used in Article 102 EWRC shall consult:

a) The TNO on the impact on the costs of transmission expansion and its ability to achieve its performance objectives of a given RMR margin;
b) The MO and SO on likely impact on costs of ancillary services procurement;
c) Users on their preferences for quality; and
d) The Trader(s) on their views of costs of supply versus quality of supply.

Article 104. Method and Process of Ancillary Services Procurement

1) Provision of spinning reserve, regulation reserve and reactive power is mandatory for all generators, except non-dispatchable renewable generators, and power pool operators.
2) At least 3 months prior to the start of the SLEM and annually thereafter the SO shall conduct a tender process to procure fast start reserve, cold start reserve, reliability must run, and black start ancillary services on contract.
3) The quantity procured shall be as determined by the SO in accordance with the methodology developed in accordance with Article 102.
4) The prices and form of contract will be in accordance with the ancillary services pricing methodology published from time to time by the EWRC, in accordance with the relevant National Public Procurement Authority (NPPA) procedures and regulations.

Article 105. Eligibility for Ancillary Services Contracts

To be eligible for each class of ancillary services contract a generator or power pool operator must meet the requirements below:

1) Fast Start Reserve

   To be eligible for a fast start reserve ancillary services contract a generator or power pool operator must:

   a) Not hold a PPA contract which separately compensates them for provision of this service; and
   b) Meet the technical requirements for provision of fast start reserve ancillary service as laid out in Article 100.

2) Cold Start Reserve

   To be eligible for a cold start reserve ancillary services contract a generator or power pool operator must:

   a) Not hold a PPA contract which separately compensates them for provision of this service; and
   b) Meet the technical requirements for provision of cold start reserve ancillary service as laid out in Article 100.

3) Reliability Must Run

   To be eligible for a reliability must run ancillary services contract a generator or power pool operator must:

   a) Not hold a PPA contract which separately compensates them for provision of this service; and
   b) Meet the technical requirements for provision of cold start reserve ancillary service as laid out in Article 100.

Article 106. Registration of Ancillary Services Capability

1) At least 3 months prior to the start of the SLEM all generators and power pool operators will register with the SO their capability to provide ancillary services in accordance with the technical requirements specified in Article 100.
2) Any generator or power pool operator connecting to the transmission network or participating in the SLEM, for the first time shall register its ancillary service capability with the SO at least 3 months before commissioning.
3) Generators or power pool operator shall advise the SO of any material change in their ancillary services capability as soon as they become aware of such change.

Article 107. Determination of Ancillary Service Marginal Costs

Prior to the start of the SLEM and periodically as required thereafter, the SO shall determine the marginal cost of provision of each ancillary service for each generator or power pool operator according to ancillary services pricing methodology published from time to time by EWRC.

Article 108. Ancillary Services Scheduling Dispatch

SO shall schedule dispatch ancillary services in real time in accordance with the dispatch methodology laid out in Section m of this Chapter.

Section m. Scheduling and Dispatch Process

Article 109. Ancillary Service Scheduling and Dispatch

1) Prior to the start of the SLEM, and periodically thereafter as required, the SO shall develop a methodology for scheduling and dispatch of ancillary services based on the following principles:
   a) Spinning reserve, and regulation reserve shall be scheduled and dispatched to ensure the frequency standards, as laid out in Article 19 are maintained, based on the lowest marginal cost of provision;
   b) Voltage support shall be scheduled and dispatched to ensure transmission network voltage standards, as per Article 32 are maintained, and based on the lowest marginal cost of provision;
   c) Fast start reserve, cold start reserve and reliability must run generation provide energy services and shall be scheduled and dispatched based on their energy offers in accordance with the energy scheduling and dispatch process laid out in the remainder of this section.
   d) Black start is not required to be scheduled and will only be dispatched once a local or system wide blackout occurs.
2) In order to achieve the objective of maintaining the frequency standard as laid out in item 1) a) above the SO shall develop appropriate security constraints to be imposed upon the scheduling and dispatch model formulation in Appendix 1.
3) In developing these constraints the SO shall follow the principles below:

a) The spinning reserve requirement should be set to cover the largest expected single contingent event in the period; and
b) Regulation requirement should be set to cover the largest expected mismatch between load and generation within the dispatch period.

Day-ahead market scheduling

Article 110. Summary of Day-ahead Scheduling

1) Day-ahead scheduling is done based on the energy offers, ancillary service marginal costs, as determined under Article 107, of all generators and power pool operators in the system, and SO's forecast of day-ahead demand developed in accordance with Article 137.
2) SO is responsible for calculation of the day-ahead schedule and provide warning about the problems that may cause insecurity of the system in the scheduled day so that the generators can adjust their bid strategy and change the maintenance schedule taking in considerations the benefit of the parties.
3) Day-ahead ancillary services scheduling is based on the methodology outlined in Article 109.
4) Day-ahead energy scheduling is based on the process outlines in Article 112 to Article 114.

Article 111. Purpose of Day-ahead Scheduling

1) The purpose of the Day-ahead schedule is to:
   a) Provide the expected scheduling profile of energy and ancillary services of each unit for the day after, in the mean time determine the state of the generators and power pool expected to connect on day D through their bidding behavior;
   b) Provide on/off schedule of the generators;
   c) Indicate the scheduling mode for each hour of the day after; and
   d) Provide the security warning (if any).

Article 112. The Software

1) The SO shall carry out the day ahead scheduling using software consistent with the generic model formulation in Appendix 1.
2) The SO shall develop a detailed model formulation consistent with the above generic formulation and submit to EWRC for approval at least 6 months prior to the SLEM start.
3) EWRC may approve, reject or amend the proposed model formulation.
4) Where EWRC rejects or amends the proposed model formulation they must state the reasons for the rejection or amendments.

5) Where EWRC rejects a proposed model formulation the SO must submit a revised model formulation within 3 months.

6) The SO is responsible for implementing the software in accordance with the approved model formulation, and obtaining an independent audit certificate confirming it has been implemented in accordance with the approved model formulation.

Article 113. Security Constraints

1) In order to achieve scheduling and dispatch that meets the principles of secure dispatch outlined in Article 82 and Article 84 the SO will need to place certain constraints on the dispatch model. In developing the formulation of these constraints the SO shall follow the process laid out below.

2) The SO is to develop a list of security constraints for the economic scheduling and dispatching process, these are to include:

   a) Transmission constraints;

   b) Power pool constraints;

   c) Generator constraints;

   d) Ancillary service requirements; and

   e) Any other constraints necessary to achieve the security principles outlined in Article 82 and Article 84.

3) The scheduling and dispatch process shall take account of these security constraints.

4) The SO must publish the formula, basis and values for all security constraints in advance and update at least weekly.

5) The SO may vary actual security constraints for real time dispatch if it is necessary to do so to achieve real time security.

6) The SO must publish, the day after dispatch occurs, the security constraints applied in the day-ahead schedule, the hour-ahead schedule the dispatch schedule, and those applied in real time dispatch, together with an explanation for any differences.

Article 114. Input Data

The input data to the day ahead schedule shall be:

a) The load forecast used is conducted and updated by SO in accordance with the procedures in Article 137;

b) Power pool and Generator energy and ancillary service offers submitted in accordance with the Market Rules and provided by the MO;

c) Power pool, generation and network maintenance plans approved in accordance with the provisions of Chapter VIII;

d) Most recent data on status of TNO, generator DCC and DC assets from SCADA system or as advised by TNO, generators DCCs or DCs; and

e) Any security constraints developed as per Article 113.

Article 115. Scheduling Timetable

The timetable for the calculation of the day ahead schedule is as follows:

a) 10AM: update all offers;

b) Before 11AM: Update the data required at Article 114;

c) Before 2PM, runs model; and

d) Before 3PM: Publish all calculated results on the website, including the expected generator scheduling for the day D.

Article 116. Model Running Procedures

1) No constraint violation penalties indicated:

   a) This regime means there is no shortage, no breach of any model constraint.

   b) The schedule is published without amendment.

2) Constraint violation penalties in solution:

   a) Since in this calculation step, the formal schedule for real time dispatch is not required, so if there are signals of redundant or lack of generation, network constraint, SO will announce these events on the web. When calculation for hour-ahead schedule is conducted, SO will adjust accordingly for proper operations;

   b) Normally, when there is signal of violated constraints, SO will deal suitably depending on each event as follows:

      i) Lack of generation signal/warning:

         (1) This case means all generators and power pool operators which bid to SLEM have been scheduled at maximum level, since this is the day ahead expected schedule, SO shall publish results and hours of lack of generation as well as the shortfall volume on the website; or

         (2) The results of model run including: expected scheduling for each hour of day ahead, hours of lack of generation; or

      ii) Redundant generation signal/warning

         (1) This event happens when total minimum capacity of all units and power pool is higher than load, SO will publish the result and announce on the website which generator units, or power pool, do not need to generate.

Article 117. Publication of Day-ahead Schedule

1) The following information shall be included in the published day-ahead schedule:

a) Expected day-ahead schedule for energy and ancillary services for each generating unit;

b) Hours with lack expected generation, or ancillary services; and

c) Hours with excess generation.

2) SO will publish the expected day-ahead schedule of all units.

3) Publication time:

a) Before 3PM every day, SO will post the information required at point 1) on the website; and

b) Before 3PM every day, SO will issue the switching requirements to TNO for the network components under its control.

Hour-ahead Scheduling

Article 118. Summary of Hour–ahead Scheduling

1) The hour – ahead scheduling is based on energy offers submitted from all generators, marginal costs of ancillary service provision as determined under Article 107, and hour-ahead demand forecast developed in accordance with Article 138. The offers are either the latest available offers or the modified ones due to fault/declined capacity in the generator, where the SO is aware of such changes.

2) SO is responsible to calculate and schedule the generators and power pool operators for energy and ancillary services hour ahead.

3) Hour-ahead ancillary services scheduling is based on the methodology outlined in Article 109.

4) Hour-ahead energy scheduling is based on the process outlines in Article 120 to Article 122.

Article 119. Purpose

The purpose of the hour-ahead schedule is:

a) To account for any changes in the system in real time;

b) To respond to the cases of declaring or re-bidding from the generators (where allowed); and

c) To create a transparent mechanism for preparation of the real time dispatch schedule in the SLEM;

Article 120. Hour-ahead Scheduling Process

1) Implemented on the hourly basis, the results of the calculation for this hour will be the inputs for the next hour calculation.

2) The hour–ahead calculation results form the basis for the dispatch for the next hour.
3) The software used shall use the same model formulation as used for day-ahead scheduling.

Article 121. Input Data

The input data for the hour-ahead schedule is:

a) Most recent load forecast used is conducted and updated by SO in accordance with the procedures in Article 138;
b) Most recent generator and power pool energy and ancillary service offers submitted in accordance with the Market Rules and provided by the MO;
c) Most recent generation, power pool and network maintenance plans approved in accordance with the provisions of Chapter VIII;
d) Most recent data on status of TNO, generator, power pool, DCC, and DC assets from SCADA system or as advised by TNO, generators power pool, or DCs; and
e) Any security constraints developed as per Article 113.

Article 122. Model Running Procedures

1) Successful running of model:
   a) This regime means there is no shortage, no constraint violation penalty indicated in solution.
   b) In this case, the results are published immediately.
2) Constraint violation penalties in results:
   a) Once having the unsuccessful signal, as indicated by a constraint violation penalty appearing in the solution, SO will review and determine if the solution is dispatchable. If they consider the solution is not dispatchable and they have to provide adjustment as in the cases listed below, then run again the program until the successful results informed/alerted. These adjustments will be recorded and become the basis for reporting.
   b) If the unsuccessful signal alerted, depending on each type of alert signal, SO will have the treatment alternatives, normally the following situations will occur:
      iii) Alert for lack of generation; and
         1) In this case, the units bid are committed until the last MWs of the bid, SO is responsible to deal with it following this orders:
         2) Schedule the additional capacity from the spinning reserve;
         3) Schedule additional capacity from regulation reserve;
         4) Expect the load shedding schedule, this should be considered as the last resort.

iv) Alert for surplus supply.

1) This situation occurs when the minimum capacity total of all the generators and power pool operators is greater than total demand, SO will respond to this in the following processes:

a) Has a right to minimize the capacities of regulation reserve generators or power pool operators;

b) Has a right to stop the reserve from the fast start reserve generators or power pool operators in order of price from high to low (even the bid price is equal to zero at the first capacity level);

i) Stop the reserve from the slow start units, the priority orders are as:

ii) The least start time; then

iii) The least start up cost, then

iv) The minimum capacity which enough for avoiding the surplus supply situation).

2) Periodically, all the generators and power pool operators in the system will provide this data for SO to use as the basis for their performance; and

3) All above adjustments will be recorded by SO, published when necessary and perform following the "careful application custom".

Article 123. Information Publication

1) Every hour the SO is to publish:

a) An expected schedule of energy and ancillary services for 4 hours –ahead and oriented to the next 4 hours.

b) Any modifications carried out under Article 122.

c) It shall include any expected demand limitations.

2) Immediately after finishing its calculation process, SO will publish the information stipulated in the item 1 of this article on the Website.

Real Time Dispatch

Article 124. Purpose

The purpose of these real time dispatch rules are to:

a) To ensure energy and ancillary service dispatch of all generators and power pool operators in the national power system is carried out as safely and transparently as possible for all participants in the SLEM; and

b) To ensure the power system is operated safely, reliably and transparently in the existing conditions.

Article 125. Dispatching Orders

1) Prior to the start of the SLEM the SO shall develop, in co-operation with all affected parties, detailed procedures for issuing, receiving and recording dispatch orders.
2) These procedures will comply with the following principles:
   a) Every dispatching order should be recorded in books, by voice recorder and/or Dispatch Information Management (DIM) system;
   b) SLEM participants must comply with properly issued dispatch orders;
   c) Back up procedures shall be in place for failure of any element of the DIM system; and
   d) Within 12 hours of real time operation, all dispatch orders related to generation scheduling, main power system operation shall be published on the Website by SO.

Article 126. Dispatch Compliance Monitoring and Reporting

1) The SO will monitor and report on compliance with dispatch instructions by generators and any dispatchable loads.
2) The SO will, from time to time, consult on and publish a set of dispatch compliance tolerance bands for all generators and dispatchable loads.
3) Such tolerance bands shall recognise:
   a) Any technical generator characteristics which limit their ability to follow dispatch instructions in real time;
   b) The impact of generator governor action, compensating for frequency deviations, on generator compliance with dispatch instructions;
   c) For non-dispatchable renewable generation the impact unforeseeable changes in energy input source may have on their ability to follow dispatch instructions;
   d) For dispatchable load any technical limits on their ability to follow dispatch instructions; and
   e) Any other matters the SO considers relevant.
4) Such dispatch compliance tolerance bands must be approved by the EWRC before they become enforceable under this Grid Code.

Article 127. Real time Operation

1) General:
   a) The real time dispatch shall be based on last hour ahead schedule for that hour as published under Article 123.
   b) Any deviations within the hour, from the hour ahead schedule will normally be undertaken either by the frequency regulating generators or spinning reserve generators.

c) In each trading period, for every change in the generation schedule for different reasons such as technical system constraints, contingencies, SO has the right to change the schedule in order to ensure the system operation is as safe as possible. However, all changes should be recorded to make the daily operation report and provide to relevant parties if required.

2) Normal mode:

a) This mode is understood as there are hardly changes in the system in term of number of generators, the transmission network, power pool, or demand compared to the last hour-ahead schedule provided before the actual operation hour.

b) The SO will aim to balance supply and demand in real time by issuing dispatch orders based on the merit order contained in the last hour-ahead schedule.

c) Any minor imbalance will be picked up by regulation reserve.

3) First contingent fault operating mode:

a) Any minor imbalance due to a first contingent event will be picked up by regulation reserve and spinning reserve ancillary services.

b) Where the SO considers that 2 b) and 3 a) above are not adequate they will start up fast start reserve generators or power pool operators based on the merit order contained in the last hour-ahead schedule.

c) SO's decisions to start the fast start reserve generators or power pool operators, and all other dispatch orders are to be recorded by SO and published into the Website in the next day.

4) Fault mode:

a) If the procedures in item 3) above have been done, however the shortage is existing, the load shedding is considered as the ultimate solution.

b) In the real time operation if the fault occurs (includes the fault in the generation or on the network), depending on the seriousness of the fault, SO has the right to order to dispatch all existing generators and power pool operators in the system, based on the merit order from the last hour ahead schedule for that hour, if available, or the merit order stack formed as per item 5), below if an hour ahead schedule is not available, as well as the orders to shed the load, in order to quickly recover the system normal operation mode.

c) All the parties shall cooperate with the SO to quickly return the system to the normal status.

d) All the above changes should be recorded by SO and aggregated in a report provided to the relevant parties when necessary and accomplished as "careful application custom".

e) The SO is responsible for developing a merit order for manual load shedding when in fault mode prior to the start of the Sierra Leone Electricity Market. In developing this merit order for manual load shedding the SO shall consult with all DCs and DCCs.

5) Market dispatch when no hour ahead schedule:

a) When no hour ahead schedule is available the SO will dispatch based on, either the most recent schedule if it considers this sufficiently valid, or a simple merit order stack of all generators and power pool operators, adjusted to account for transmission and security constraints as the SO considers appropriate.

b) Where offers for a generator or power pool operators are available then those offers should be used in forming the simple merit order stack above. Where offers are not available for a generator or power pool operator then a default bid shall be formed by the SO based on the registered capacity of that generator, subject only to the generator not being on an approved outage, and the maximum bid price allowed for that generator as determined under the Market Rules.

Article 128. Market Suspension

Where the Market has been suspended for any reason the SO shall dispatch all generators and power pool operators according to the procedures laid out in Article 127 item 5).

Section n. Fault Resolution Procedures

Article 129. Information Exchange

1) The SO has overall responsibility for resolution of faults affecting safe and reliable operation of the power system.

2) TNOs shall immediately inform the SO and institutions, individuals using transmission network on operation when there is fault of any component of transmission network, which can affect operation of institutions, individuals using transmission network.

3) Power pool operators shall immediately inform the SO of any operation or fault that can affect safety or reliability in operation of power system.

4) Generators or users shall immediately inform the SO of any operation or fault that can affect safety or reliability in operation of power system.

5) When receiving the announcement as specified in items 2) or 3) of this article, the SO shall immediately contact the TNOs, power pool operators, power generation plants, or users in order to find out cause. The TNOs, power pool operators, generators or users shall provide sufficient information, answer exactly questions and requirements raised by the SO.

6) The contents of the announcement, report or answer are stipulated in item 2), 3), or 4) of this article, must include:

   a) Name and position of person who provides announcement, report or answer; time of announcement, report or answer (hour, date, month, year); and

   b) Details related to operation, clearing faults or risks which happened.

7) After carrying out stipulations in item 5) of this article, the report on fault or answers to questions related to fault shall be provided in writing or voice and specified as follows:

a) Contents of report or answer shall include details of fault cause or life damage, affections or damage caused by faults or accidents; overcoming measures and results of implementing these measures;

b) In case the fault can be cleared immediately, report or answer can be in form of voice the receiver shall confirm accuracy by repeating back the report for confirmation by the reporter;

c) In case faults happen in generating station, the generator shall report or answer questions. If fault happens on power system or power pool connected to the transmission network, user or power pool operator shall report on fault or answer questions; if fault happens on the transmission network, the TNO shall report or answer questions; and

d) In case the fault is related to parties such as generators, user's power system connected to transmission network, and if a meeting is required by one party, the SO shall organize a meeting with related parties, with invited representatives of institutions, individuals using transmission network. Procedures for carrying out, the meeting shall be decided by participants and conclusions of the meeting will be agreed by all parties and effective for implementation.

8) Operations needed to be announced in writing or recorded voice includes:

a) Operation stopped for testing parts of power plant related to reliability of the power system;

b) Operation stopped for testing parts of power system or parts of user’s network related to reliability of the power system;

c) Unplanned checking, testing item of power plants, of users;

d) Operation of circuit breakers earthing switches, disconnectors without complying with regulations of the SO; and

e) Any other operation carried out by institutions, individuals using National Power system.

Article 130. Confidentiality

1) All information related to operation or faults shall be preserved as "confidential" and only supplied to the third party in the following cases:

a) It is already publicly available;

b) The third party has provided the SO with proof of legal entitlement to the information; or

c) There is a legal requirement to publish.

Section o. Safety Coordination

Article 131. TNOs to Develop Safety Co-ordination Procedures

1) Prior to the start of the SLEM and periodically as required after that each TNO shall develop and publish a set of safety co-ordination procedures.
2) The TNOs shall submit such safety co-ordination procedures to EWRC for approval and such procedures shall not be valid unless approved by EWRC.
3) The procedures must, as a minimum cover:
    a. Procedures for co-ordination of operation transmission network assets with the assets of users; and
    b. Procedures for ensuring the safety of all personnel operating or maintaining transmission network assets or assets connected to the transmission network.
4) Such procedures must be compliant with all relevant safety laws in Sierra Leone.
5) Such procedures must be agreed between each TNO and relevant Users.

Article 132. TNOs and Users to Assign Safety Co-ordinators

1) Each TNO and each user is to assign a safety co-ordinator for all operation and maintenance of the transmission network and all transmission network connected equipment.
2) It shall be the responsibility of the safety co-ordinator for each party to ensure appropriate safety procedures are put in place and followed for all operation and maintenance of the transmission network and all transmission network connected equipment.

Chapter VII. Demand Forecasting

Article 133. General Regulations on Demand Forecast

1) Power demand forecasting underpins many aspects of power system planning and operation. This chapter defines the roles responsibilities and processes for the different power demand forecasts.
2) Responsibilities in power demand forecast:
   a) SO is responsible to forecast power demand for operating plan annually, monthly, weekly, daily and hourly operation mode; and
   b) The DCs, DCCs and power pool operators shall be responsible for providing SO with their data on power demand forecast. This forecast is to be for demand at the point of connection to the transmission network, including the impact of any embedded non-dispatchable renewable generation, and is to include both active and reactive power.
3) Where, in producing the demand forecasts required under this chapter, the SO decides to deviate from the demand forecast data provided by DCs, DCCs, and power pool operators, the SO will publish a report on where it deviated from the forecast provided by the DCs, DCCs and power pool operators and the reasons for such deviation. Such reports shall be provide by the SO within 10 working days of the month in which their forecast was completed.

Article 134. Demand Forecast for 5 Yearly Operation

1) Prior to the start of the SLEM, the SO and TNOs shall agree on a timetable for preparation of the annual 5 year ahead demand forecast and publish this timetable to all users.
2) DCs, DCCs and power pool operators shall provide their forecast of demand for the coming year and the next 5 years to the SO by the date required in the time table published in accordance with item 1) above. This forecast is to include hourly forecasts of active and reactive power requirements at the point of connection to the transmission network.
3) Each year the SO is responsible for producing the power demand forecast for the 5 year ahead operation plan.
4) Power demand forecast for 5 year ahead operation plan is to include:
   a) Electricity sold to distributors, organizations or individuals who connect directly to the transmission networks;
   b) The impact of any embedded generation, including non-dispatchable renewable generation;
   c) Power pool transactions;
   d) Electricity for power generation and power transmission loss;
   e) Day-time peak demand, and night time minimum demand; and
   f) Ancillary service requirements, including all types of reserve.

5) When power demand is forecasted for 5 year ahead operation plan, it should consider the following factors:
   a) Power demand forecast data which has been used in TEPs as per Chapter V;
   b) Annual maximum power demand forecast data and annual load factor under the power system planning;
   c) Statistics on electricity output sold to distributors, organizations or individuals those who directly connect to the transmission networks;
   d) Statistics on day-time and night-time peak load;
   e) Ancillary service requirements; and
   f) Other necessary information.
6) Power demand forecast for the following year must be completed before the date required in the timetable published in accordance with item 1) above.

Article 135. Demand Forecast for Monthly Operation

1) DCs, DCCs and power pool operators shall provide their forecast of demand for the coming month to the SO by ten (10) working days before the last working day of the month. This forecast is to include hourly forecasts of active and reactive power requirements at the point of connection to the transmission network.
2) The SO is responsible for producing the power demand forecast for the monthly operation mode.
3) Content of power demand forecast for monthly operation mode includes:
   a) Electricity is sold to distributors, organizations or individuals who directly connect to the transmission networks;
   b) The impact of any embedded generation, including non-dispatchable renewable generation;
   c) Electricity for power pool transactions;
   d) Electricity for power generation and power transmission loss;
   e) Day-time and night-time peak load; and
   f) Ancillary service requirements including all types of reserve.
4) When power demand is forecasted for monthly operation plan, it should consider the following factors:
   a) Power demand forecast data which has been used in annual operation mode;
   b) Statistics on electricity output sold to distributors, organizations or individuals those who directly connect to the transmission networks;
   c) Statistics on day-time and night-time peak load;
   d) Ancillary service requirements; and
   e) Other necessary information.

5) Forecasting power demand for next month must be completed five (5) days before the last working day of previous month.

Article 136. Demand Forecast for Weekly Operation

1) DCs, DCCs and power pool operators shall provide their forecast of demand for the coming week to the SO by 0930hrs of each Tuesday. This forecast is to include hourly forecasts of active and reactive power requirements at the point of connection to the transmission networks.
2) The SO is responsible for producing the power demand forecast for the weekly operation mode.
3) Content of demand forecast for weekly operation mode shall include:
   a) Electricity is sold to distributors, organizations or individuals who directly connect to the transmission network;
   b) The impact of any embedded generation, including non-dispatchable renewable generation;
   c) Electricity for power pool transactions;
   d) Electricity for power generation and power transmission loss;
   e) Day-time and night-time peak load; and
   f) Ancillary service requirements including all types of reserve.
4) When power demand is forecasted for weekly operation plan, it should consider the following factors:
   a) Power demand forecast data which has been used in monthly operation mode;
   b) Statistics on power generation output selling to distributors, organizations and individuals who directly connect to the transmission network;
   c) Statistics on daytime and night time peak load;
   d) Ancillary service requirements; and
   e) Other necessary information.
5) Power demand forecast for weekly operation mode must be completed before 0930hrs each Wednesday.

Article 137. Demand Forecast for Daily Operation

1) DCs, DCCs and power pool operators shall provide their forecast of demand for the coming 24hrs to the SO twice per day at 0830hrs and 2030hrs of each day. This forecast is to include hourly forecasts of active and reactive power requirements at the point of connection to the transmission network.
2) The SO is responsible for producing the power demand forecast for the daily operation mode

3) Power demand forecast for daily operation mode shall include:
   a) Power demand should be met, of which electricity sold to distributors, power pools, organizations and. individuals those who directly connect to the transmission networks, electric power for production and power transmission loss;
   b) The impact of any embedded generation, including non-dispatchable renewable generation;
   c) Values and the time when daytime and nigh time peak load occurs; and
   d) Ancillary service requirements including all types of reserve.
4) When power demand is going to be forecasted for daily operation mode, it is necessary to take the following factors into consideration:
   a) Power demand forecast data has been used in forecasting weekly operation mode;
   b) Statistics (up to the latest day) on electricity sold to distributors, organizations;
   c) Individuals who are directly connected to the transmission networks;
   d) Weather forecast of the day needed for setting out operation mode; and
   e) Other necessary information.
5) Power demand forecast for operation mode of next 24 hours must be completed before 0900hrs and 2100hrs of each day.

Article 138. Demand Forecast for Hourly Operation

1) The SO is responsible for the power demand forecast for hourly operation mode.
2) Power demand forecast for hourly operation mode shall include:
   a) Power demand should be met, of which electricity sold to distributors, power pools, organizations and. individuals those who directly connect to the transmission network, electric power for production and power transmission loss;
   b) The impact of any embedded generation, including non-dispatchable renewable generation; and
   c) Variation of demand within the hour.
3) When power demand is going to be forecasted for daily operation mode, it is necessary to take the following factors into consideration:
      i) Power demand forecast data has been used in forecasting daily operation mode;
      ii) SCADA information on current demand;
      iii) Latest weather forecast; and
      iv) Other necessary information the SO considers necessary.
4) Power demand forecast for hourly operation mode must be completed 10 minutes before the hour and cover the next 4 hours.

Chapter VIII. Outage Planning Process

Section p. Equipment Maintenance and Repair

Article 139. General Regulation

1) Maintenance and repair schedules of equipment operated by generator(s), TNO, DC, DCC or power pool operators, which is designated by the SO as impacting on power system operation, shall be submitted to SO by the entity managing operation of their own equipment.
2) The SO is responsible for co-ordination of all maintenance and repair schedules to ensure overall security of supply.
3) The SO will co-ordinate all maintenance and repair schedule with the aim of operating the power system safely, stably and efficiently; balancing power generation capacity and demand, ensuring adequate ancillary services, capacity margin and energy margin.
4) The TNOs and all users must comply with SO instructions on outages.
5) The SO shall assess the impact of proposed outages on security of supply adequacy in accordance with Section q of this chapter.
6) Maintenance and repair schedule shall comprise 12 months ahead maintenance and repair schedule, in addition monthly, weekly and daily maintenance and repair schedules. In addition a 2 years ahead maintenance plan shall be provided by generators, TNOs, DCs, DCCs and transmission users.
7) 12 months ahead maintenance and repair schedule shall be worked out separately. Monthly, weekly and daily maintenance and repair schedules shall be set up and notified to related parties as a part of monthly, weekly and daily operation mode.
8) The 2 years ahead maintenance plan will be an indicative plan only.
9) Time for submission of maintenance and repair schedule shall be as determined by the SO from time to time.
10) Details to be included in maintenance and repair schedules are:
    a) Name and location of equipment that needs to be maintained and repaired;
    b) Description of maintenance and repair;
    c) Estimated time for commencing and completing maintenance; and
    d) Other related requirements.

Article 140. SO to Develop Outage Co-ordination Plan

1) In order to facilitate economic planning of outages the SO shall develop an outage planning co-ordination process.
2) The outage planning process will cover various planning periods from 2 years ahead, 12 months ahead, to one month ahead, to week ahead and day ahead.

3) The aim of the co-ordination process will be to co-ordinate all equipment outages so as to minimise the overall impact on security of supply.
4) The TNOs and all generators, DCs and DCCs connected to the transmission networks shall advise the SO on a quarterly basis of their proposed outages for the next 12 months. They shall also annually advise the SO of their 2 years ahead maintenance plans.
5) The SO, will keep all such information provided to it confidential.
6) On the basis of outage information provided to it the SO will develop a coordinated outage plan for the transmission networks and all connected equipment, with the aim of minimising the impact on overall security of supply.
7) Where necessary the SO will negotiate with individual parties concerning their proposed outages in order to minimise overall impact on security of supply.
8) On the basis of the co-ordinated outage plan the SO will publish and officially communicate, to each affected party, the following plans relating to their equipment:
   a) 2 years ahead plan of proposed equipment outages;
   b) 12 months ahead plan of proposed equipment outages;
   c) Monthly plan of proposed equipment outages;
   d) Weekly plan of proposed equipment outages; and
   e) Daily plan of proposed equipment outages.
9) The SO will publish these outage plans with the following frequency:
   a) 2 years ahead plan to be updated and published annually;
   b) 12 months ahead plan to be updated and published quarterly / every three months;
   c) Monthly plan to be updated and published weekly;
   d) Weekly plan to be updated and published twice per week for the next 7 days; and
   e) Daily outage plan to be published twice per day, looking forward the next 24 hours.
10) For the avoidance of doubt the SO will only publish outage information on individual equipment outages to the equipment operator and / or affected parties. Public information on equipment outages shall be aggregated.

Article 141. Prioritization of Outages

1) Where, in developing the above outage co-ordination plan, the SO determines that granting one or more outages would cause security of supply requirements to not be met then the SO may refuse an outage request.
2) Before declining an outage request the SO must prioritise outages as follows:
   a) Generation outages shall have precedence over transmission outages;
   b) Generation outages shall be prioritised according to their impact on the security of supply and the cost of supply to consumers, based on bid cap prices for each generator, with the outage with least impact on cost of supply to consumers having highest priority; and
   c) If two or more generator outages have identical impact on security and cost of supply to consumers then the outage lodged first will have highest priority.
3) Based on the priorities determined according to 2) above the SO will decline sufficient, but no more, outages until security of supply requirements are met.

Article 142. Registering Equipment Outages

1) The party submitting the outage request shall classify each outage as follows:
   a) Maintenance and repair as scheduled: Registering to isolate equipment for maintenance and repair on the basis of schedule that has been developed by SO. That is scheduled maintenance and repair;
   b) Maintenance and repair out of schedule: Registering to isolate equipment for maintenance and repair independently from schedule that has been developed by SO. That is unscheduled maintenance and repair; or
   c) Fixing fault: Registering to isolate equipment in operation but facing the risk of failure shall be called fixing fault registration.
2) Each outage request shall include:
   a) Name and location of equipment;
   b) Description of main work;
   c) Estimated time for starting maintenance and repair;
   d) Estimated time for commissioning and testing;
   e) Estimated timing for isolation of equipment and for returning it to operation; and
   f) Other necessary information.
3) The SO shall specify procedures and formalities for isolating equipment for maintenance and repair as well as putting same into operation.
4) Except where safety of equipment or personnel is in imminent danger or when a reduced security notice has been issued, then in that case, time schedule for isolating equipment must be changed. Entities managing operation of their own equipment shall submit a revised outage request with SO at least 48 hours before isolating equipment for maintenance and repair, regardless of scheduled or unscheduled maintenance and repair.
5) Where safety of equipment or personnel is in imminent danger, then entities managing operation of their own equipment may remove such equipment from service as is necessary to avoid such personnel or equipment danger. In doing so they shall provide as much notice to the SO of such emergency removal from service as they can reasonably provide.
6) Where a reduced security notice has been issued under Article 87, then entities managing operation of their own equipment may return such equipment from an approved outage earlier than planned with less than 48 hours' notice, provided at least 4 hours' notice has been given to the SO.

Section q. System Security Assessment Process

Article 143. Overview of System Security Assessment

1) Medium and short term security assessments are undertaken to ensure security of supply can be maintained throughout the two years and the next 12 months.

2) System Security Assessment is a process, based on available data and information, to analyze and announce the total projected usable capacities and load together with system security requirements in the medium and short term. Information from this projection serves parties in scheduling generation, planning equipment maintenance, and participating in balancing supply and demand before intervention by the SO for system security.

3) As part of the assessment process generators, DCs and the TNOs are to submit to the SO their proposed outage plans.

4) Where the SO considers a proposed outage may jeopardize security of supply it may refuse that outage.

5) The SO may only refuse an outage on the basis of a reasonable probability of loss of supply occurring should that outage proceed as planned.

6) The SO is responsible for developing, managing and operating the System Security Assessment process and publication of System Security Assessment information in accordance with the timetable it will publish from time to time. The information published shall be detailed, highlighting possible situations, in which the system security violations occur;

7) Parties to this Grid Code are responsible for supplying the SO with all information relevant for System Security Assessment in accordance with the timetable provided by the SO. Information for submission consists of: transmission network maintenance and repair plans, Generating Units maintenance and repair plans, Available Capacity of Generating Units, any generator energy constraints, Transmission Network capacity and planned outages, and other relevant information.

Article 144. SO to Define Energy Margin and Capacity Margin

1) As part of both the ancillary service procurement process and security assessment process the SO is required to define measures of both capacity margin and energy margin. Prior to the start of the SLEM the SO shall propose a process for defining methods of calculation and operational standards for capacity margin and energy margin. They shall submit these to EWRC for approval at least 1 month before the scheduled start of the SLEM. The approved method of calculation and standard for each shall form the basis of the margin assessment process under Article 146 and Article 147.
2) In developing these methodologies for defining a prudent capacity margin and prudent energy margin the SO shall adhere to the following principles:
    a) Setting a prudent capacity margin:
        i. Capacity margin is the difference between the available generation capacity, including power pool imports, in a period and the expected maximum demand, including power pool exports, in that period.
        ii. An economically optimal capacity margin is where the marginal cost of expected unserved energy, due to the statistical variability of unplanned generation outages and the statistical variability of demand, is equal to the marginal cost of procuring additional reserves to avoid such unserved energy.

iii. A prudent capacity margin is where a prudent margin is added to the economically optimal level of capacity margin, to take account of uncertainty in the input variables of the capacity margin calculation.

iv. Such a prudent margin is to be determined from time to time by EWRC as per Article 145.

b) Setting a prudent energy margin:

i. Energy margin is the difference between the available energy from non-hydro generation, including power pool imports, in a period and the expected energy demand, including power pool exports, in that period minus the expected hydro energy generation.

ii. An economically optimal energy margin is where the marginal cost of expected unserved energy, due to the statistical variability of hydro energy output over that period, is equal to the marginal cost of procuring another MW of cold start reserve to avoid such unserved energy.

iii. A prudent energy margin is where a prudent margin is added to the economically optimal level of energy margin, to take account of the uncertainty in the input variables of the energy margin calculation.

iv. Such a prudent margin is to be determined from time to time by EWRC as per Article 145.

3) In calculating the capacity margin and energy margin above the SO shall use the following input variables, for the following situations:

a) Where Capacity Margin is to be used for Fast start reserve Procurement planning

i. Generator capacity shall be the registered capacity of all licenced generators, excluding those holding fast start contracts, and the expected peak power pool imports.

ii. Forced outage rate shall be either the historical forced outage rate for each generator and power pool imports, where available, or the SO's reasonable estimate of industry best practice forced outage rate for that class of generator, or power pool imports.

iii. Demand shall be the SO's forecast of demand for that period, prepared in accordance with Chapter VII.

iv. Cost of unserved energy will be the expected unserved energy, as derived from the statistical probability of demand exceeding available capacity, multiplied by the SO's reasonable estimate of Value of Lost Load for unexpected demand interruptions.

b) Where Capacity Margin is to be used for Outage Planning:

i. Generator capacity shall be the declared available capacity of all generators, or declared power pool peak import capacity.

ii. Forced outage rate shall be either the historical forced outage rate for each generator, where available, or the SO's reasonable estimate of industry best practice forced outage rate for that class of generator.

iii. Demand shall be the SO's forecast of demand for that period, prepared in accordance with Chapter VII.

iv. Cost of unserved energy will be the expected unserved energy, as derived from the statistical probability of demand exceeding available capacity, multiplied by the SO's reasonable estimate of Value of Lost Load for unexpected demand interruptions.

c) Where Energy Margin is to be used for Cold start reserve Procurement planning
   i. Thermal generator energy capacity shall be the registered capacity of all licenced generators or power pool imports, excluding those who hold a cold start contract.
   ii. Thermal generator, and power pool imports, expected energy output shall take into account any reasonably expected fuel constraints.
   iii. Forced outage rate shall be either the historical forced outage rate for each generator or power pool imports, where available, or the SO's reasonable estimate of industry best practice forced outage rate for that class of generator.
   iv. Hydro generator expected energy output variability will be derived from either historical records of actual hydro generator output or forecasts of expected hydro generator output variability derived from appropriate rainfall or hydrological records.
   v. Energy demand shall be the SO's forecast of energy demand for that period, prepared in accordance with Chapter VII.
   vi. Cost of unserved energy will be the expected unserved energy, as derived from the statistical probability of energy demand exceeding available energy capability (taking into account hydro variability), multiplied by the SO's reasonable estimate of Value of Lost Load for demand interruptions where some reasonable degree of notice of energy shortage is possible.

d) Where Energy Margin is to be used for outage planning
   i. Thermal generator, or power pool, energy capacity shall be the generators declared energy capability over that time period.
   ii. Forced outage rate shall be either the historical forced outage rate for each generator, where available, or the SO's reasonable estimate of industry best practice forced outage rate for that class of generator.
   iii. Hydro generator expected energy output variability will be derived from available storage levels at the start of the period and either historical records of actual hydro generator output or forecasts of expected hydro generator output variability derived from appropriate rainfall or hydrological records.
   iv. Energy demand shall be the SO's forecast of energy demand for that period, prepared in accordance with Chapter VII.
   v. Cost of unserved energy will be the expected unserved energy, as derived from the statistical probability of energy demand exceeding available energy capability (taking into account hydro variability), multiplied by the SO's reasonable estimate of Value of Lost Load for demand interruptions where some reasonable degree of notice of energy shortage is possible.

Article 145. EWRC to Determine Prudent Margins for Capacity Margin and Energy Margin

1) EWRC shall, before the start of the Sierra Leone Electricity Market and from time to time thereafter, determine a prudent capacity margin and a prudent energy margin to be added to the optimal capacity margin and optimal energy margin.

2) In determining the prudent energy margin and prudent capacity margin it will consult:
    a. The MO and SO on likely impact on costs of ancillary services procurement;
    b. The SO on likely impact on its ability to achieve its target performance measures;
    c. Users on their preferences for quality; and
    d. The trader(s) on their views of costs of supply versus quality of supply.

Article 146. Medium Term System Security Assessment

1) The period for the 2 years ahead security assessment is from the first of the month after the announcement to the last month of two years ahead medium-term System Security Assessment with monthly resolution.

2) The period for the 12 months medium-term System Security Assessment is from the next Monday after the announcement time of the 12 months medium term System Security Assessment to the last week of the next 12 months with weekly resolution.

3) Once every year the SO shall publish the 2 years ahead medium-term System Security Assessment information.

4) Once every 3 months, the SO shall publish a 12 months medium-term System Security Assessment information.

5) Every week, the SO shall update and publish the medium term System Security Assessment for the next 8 weeks inclusive.

6) The SO is responsible for preparing input data of medium term System Security Assessment, as follows:

    a) Forecast demand of power system and for each region, including peak demand, total energy requirements and output;

    b) Typical demand chart for every week for system and each region;

    c) Weekly reliable energy provided by hydro generators taking into account storage and expected inflows in that period;

    d) Weekly reliable energy provided by thermal generators taking into account their expected availability and any expected fuel supply constraints;

    e) Expected generator and transmission forced outage rates;

    f) System ancillary service requirements; and

    g) Projected transmission network constraints.

7) The SO is responsible for providing the timetable for inputs to the security assessment process.

8) In accordance with the timetable provided from time to time by the SO, Generators and power pool operators are responsible for availing the SO with data of medium term System Security Assessment, as follows:

    a) Any proposed equipment outages;

b) Weekly Available Capacity of Generating Units; and

c) Weekly energy constraints of Generating Units.

9) This information shall be provided by Generators, and power pool operators, in a form agreed by the SO.

10) In accordance with the timetable provided from time to time by the SO, TNOs are responsible for availing approved transmission network maintenance and repair schedule. If these plans have possible impact on the generating ability of Generating Units (or a group of Generating Units), the SO has the right to adjust capacity of each generating unit (group of generators) and announce transmission network constraints for Parties.

11) In accordance with the timetable provided from time to time by the SO, DCs, DCCs and power pool operators are responsible for availing demand plans at connection (metering/trading) point.

12) The SO shall calculate the following in the medium term System Security Assessment:

a) Total usable capacity, with account for the energy constraints of Generating Units and power pool operators, the repairs and maintenance plans of the transmission network, power pool and Generating Units;

b) Ancillary service requirements;

c) System capacity margin;

d) System energy margin; and

e) Projected transmission network constraints.

13) The SO is responsible for preparing medium term system security assessment process, the medium term load forecast methodology and publication of system security assessment process and methodology for Parties.

14) Where the SO considers the system capacity margin or system energy margin are below a prudent level they may refuse an equipment outage proposed under item 8)a) above.

15) Where the SO considers the system capacity margin or system energy margin are below a prudent level they may refuse a TNO outage proposed under item 10) above.

16) Where the SO refuses a proposed outage under items 14) or 15) above the affected party shall resubmit a revised outage proposal within the time advised by the SO.

17) The SO will then revise the medium term System Security Assessment, and if it is satisfied with the resulting system capacity margin and system energy margin, will approve the revised outage proposal. If not it shall refuse the outage and the process recommences at step 16) above.

18) Once the SO is satisfied with the medium term System Security Assessment it will publish it in full.

Article 147. Short - term System Security Assessment

1) The period for the short-term System Security Assessment is eight (8) days starting from 24h00 of the short-term System Security Assessment announcement day to 0h00 of eighth day after with hourly resolution.
2) Every day, the SO shall publish the short-term System Security Assessment.
3) SO is responsible for preparing data of short term System Security Assessment, as follows:
   a) Load demand forecast;
   b) Expected generator and transmission forced outage rates;
   c) Expected generator energy capability;
   d) System ancillary service requirements; and
   e) Projected network constraints.
4) SO is responsible for providing the timetable for inputs to the security assessment process.
5) Generators, power pool operators, DCCs and DCs are responsible for providing the SO with data of short term System Security Assessment, as follows:
   a) Any proposed outages;
   b) Available Capacity of Generating Units or power pool for each Trading Interval;
   c) Available energy capability of the Generating Units or power pool for each Trading Interval;
   d) Announced Capacity of Generating Units or power pool for each Trading Interval;
   e) Start-up and stopping time of Generating Units and power pool; and
   f) Lowest stable output capacity of Generating Units or power pool.
6) In accordance with the timetable provided by the SO, TNOs are responsible for providing proposed transmission network maintenance and repair schedule for SO. In case, capacity of each generating unit have impacted on maintenance and repair schedule, SO has the right to adjust capacity of each generating unit or power pool and announce transmission network constraints for Parties.
7) The SO shall calculate the following in the short-term system security assessment:
   a) Total usable capacity, with account for the repairs and maintenance plans of the Transmission Network;
   b) Total Announcement capacity, with account for the repairs and maintenance plans of the Transmission Network;
   c) System demand forecast;
   d) Ancillary service requirements;
   e) System capacity margin;
   f) System energy margin; and

g) Projected transmission network constraints.

8) The SO is responsible for developing short term System Security Assessment process, the short term load forecast methodology and publish information to related Parties.

9) Where the SO considers the system capacity margin or system energy margin are below a prudent level they may refuse a generator outage proposed.

10) Where the SO considers the system capacity margin or system energy margin are below a prudent level they may refuse a TNO outage proposed.

11) Where the SO refuses a proposed outage under items 9) or 10) above the affected party shall resubmit a revised outage proposal within the time advised by the SO.

12) The SO will then revise the short-term System Security Assessment, and if it is satisfied with the resulting system capacity margin and system energy margin will approve the revised outage proposal. If not it shall refuse the outage and the process recommences at step 11) above.

13) Once the SO is satisfied with the short-term System Security Assessment it will publish it in full.

Section r. Unplanned Outages

Article 148. Emergency Equipment Outages

In the necessary case, when equipment is being in operation, risk to staff and equipment is identified, operating staff of the entity managing operation of that equipment has right to immediately separate that equipment from the power system, and shall be fully responsible for their decision. For the avoidance of doubt this includes automatic separation of equipment by protection devices or other automatic devices.

Article 149. Report on Emergency Outage

Where a party has taken equipment out of operation under the provisions of Article 148 they will:

a) As soon as possible, update any offer associated with that equipment within the provisions of the Market Rules or PPA contract;
b) As soon as possible advise the SO of the change in status of that equipment;
c) Within 24 hours provide a report to EWRC on the reasons for taking the equipment out of service, including whether it was due to a bona fide physical reason.

Chapter IX. Performance Indicators

Article 150. General Requirements

The SO and TNOs shall publish, at least once per month, certain performance indicators which are intended to provide an indication of how well they are fulfilling their obligations and objectives under this Grid Code.

Article 151. SO Performance Indicators

The SO shall publish, at least once per month the following performance indicators:

a) The number of times in the month when the frequency was outside performance target range, as specified in Article 19;

b) Number and cause of Total Outages;

c) Unserved Energy due to Total Outages;

d) Total monthly cost of each type of reserve;

e) Total monthly cost of regulation reserve;

f) Total monthly cost of black start;

g) Level of each type of operational reserve, by hour and reserve type;

h) Number of times and duration when reserve was below SO requirements; and

i) The demand forecast error for each of the demand forecasts produced by the SO under Chapter VII.

Article 152. TNOs Performance Indicators

Each TNO shall publish, at least once per month the following performance indicators:

a) The period over which each indicator has been calculated; and

b) A list of all Transmission Network lines and transformers that were out of service in the measurement period, and for each outage:

   i) The start time of the outage;

   ii) The finish time of the outage; and

   iii) Whether the outage was planned or unplanned.

c) A list of all busbars where the voltage was outside the standards specified in Article 32 during the measurement period, and for each such busbar:

   i) The start time of the voltage deviation;

   ii) The finish time of the voltage deviation;

   iii) The minimum and maximum voltage experienced during the deviation period;

   iv) Whether the voltage deviation was due to a contingent event or not; and

v) Details of any related contingent events.

d) Summary information on transmission reliability calculated as follows:

i) Total number of unplanned interruptions to supply where such interruptions were due solely to an outage on the TNO network and the outage was of more than one (1) minute duration; and

ii) For such unplanned interruptions, as per item i) above, the total unserved energy in MWhs;

e) The total system losses for that month.

f) A list of any incidents that led to the other performance targets specified in Chapter III Section b and Section c not being met. Together with details of why these targets were not met and recommendations for any proposed changes to this Grid Code, that may assist them in meeting these targets.

Chapter X. Transmission Metering

Section s. Scope and Application of Grid Code Metering

Article 153. Scope

This chapter stipulates the procedures and requirements for metering activities for Generators, Power Pool Operators, DCs and DCCs at their point of connection to the transmission network. Metering is to be provided and maintained by the TNO(s) at connection points agreed with the relevant party. Various metering service providers and their roles are defined in this chapter.

Article 154. Relationship to PPAs.

The provisions of this chapter set out a minimum standard required for connection. Separate commercial arrangements for revenue metering may be specified elsewhere, such as in Power Purchase Agreements (PPAs).

Article 155. Application

This chapter applies to the service providers and the Generators, Traders, Power Pool Operators, Sellers, DCs and DCCs connected to or using the transmission network, it applies to:

a) Market Operator (MO);
b) Trader(s);
c) The Generators;
d) The Power Pool Operator(s);
e) The Transmission Network Owner(s) (TNOs);
f) The Distribution Companies (DCs);
g) The Direct Connected Consumers (DCCs);
h) The System Operator (SO); and
i) Technical and supporting service providers, including:
    i) Meter Testing Service Provider (MTSP);
    ii) Metering Data Management Service Provider (MDMSP);
    iii) Information Service Provider (ISP); and
    iv) The Auditor.

Section t. Metering Rights and Responsibilities

Article 156. Generator Rights and Responsibilities

Generators have the following rights:

a) The right to check and dispute metering values forwarded for settlement;
b) The right to have an independent test of a metering installation undertaken;
c) The right to have an independent audit of the meter data handling process

undertaken; and

d) The right to agree, with the relevant parties, the metering point location and arrangement.

Article 157. Power Pool Operator Rights and Responsibilities

Power Pool Operators have the following rights:

a) The right to check and dispute metering values forwarded for settlement;
b) The right to have an independent test of a metering installation undertaken;
c) The right to have an independent audit of the meter data handling process undertaken; and
d) The right to agree, with the relevant parties, the metering point location and arrangement.

Article 158. DC and DCC Rights and Responsibilities

DCs and DCCs have the following rights:

a) The right to check and dispute metering values forwarded for settlement;
b) The right to have an independent test of a metering installation undertaken;
c) The right to have an independent audit of the meter data handling process undertaken; and
d) The right to agree, with the relevant parties, the metering point location and arrangement.

Article 159. Trader Rights and Responsibilities

1. The Trader has the following rights:
   a) The right to agree, with the relevant parties, the metering point for a connection;
   b) The right to check and dispute metering values forwarded for settlement;
   c) The right to have an independent test of a metering installation undertaken; and
   d) The right to have an independent audit of the meter data handling process undertaken.

2. The Trader has the following responsibilities:
   a) Negotiate and come to an agreement regarding metering points with the DCs and DCCs;
   b) In coordination with the related entities to confirm the metered data and the power to be the basis of payment; and
   c) Check and collate the metered data to find out any abnormal status and request the authorized entity to timely deal with it.

Article 160. TNOs Rights and Responsibilities

1. The TNOs have the following rights:
   a) The right to check and dispute metering values forwarded for settlement;
   b) The right to require an independent test of a metering installation be undertaken;
   c) The right to have an independent audit of the meter data handling process undertaken;

d) The right to use metering data for the purposes of operating its business;
e) The right to agree to the location of any metering equipment to be installed upon its premises; and
f) The right to agree to any metering adjustment factors where metering equipment is installed upon its premises.

2. The TNOs have the following responsibilities:
   a) Providing, operating and maintaining the metering equipment at each metering site, up to and including the local data acquisition server and software, to the communications port of the local server; and
   b) In performing this responsibility the TNOs shall:
      i) Invest, install, check and takeover of the metering system, sealing system; equipment serving for data collection and transmission at the metering points;
      ii) Manage, operate, preside of the maintenance, replacement of the equipment in the metering system, data collection and transmission system during the operation;
      iii) Negotiate and come to an agreement with the Trader, generator and power pool operator regarding location of the metering points relating to the main metering system and backup metering systems;
      iv) Maintain the information and list of the metering systems;
      v) Implement any agreed amendments to the metering system and the power offtake or delivery method;
      vi) Provide the MDMSP with the information of the metering system in the assets managed by that entity to update in the collection, processing and archiving program;
      vii) Coordinate with the MDMSP in collecting, processing, archiving, confidential management and transmission of the metering data in the meters installed on the TNO's premises. This should be done in an adequate, timely, accurate manner in line with this Grid Code, and in a mode compatible with any communications protocol advised by the MDMSP;
      viii) Keep the MO and other related entities informed of the cases of metering points amendment, addition or cancellation;
      ix) Operation and management of the data collection and transmission system;
      x) In coordination with the related entities to confirm the metered data and the power production at the power plant to be the basis of payment between the parties;
      xi) Facilitate for the MDMSP and other related entities to enter the plant premises to write down the metered data and confirm the off taken and traded power;
      xii) Enter into contracts with the MTSP, MDMSP, and ISP to implement the work related to the metering and data collection and transmission system installed at their premises; and
      xiii) Allow access to their equipment for testing and auditing.

Article 161. SO Rights and Responsibilities

1. The SO has the following rights:
   a) The right to use metering data for system operation purposes.

2. The SO has the following responsibilities:
   a) Keep confidential any metering information provided to it.

Article 162. MO Rights and Responsibilities

1. The MO has the following rights:
   a) The right to be notified of the metering point for a connection;
   b) The right to appoint and sign contracts with the MDMSP and permit the MDMSP to choose the ISP;
   c) The right to enter into contracts with the Auditor;
   d) The right to use metering data for settlement purposes; and
   e) The right to require audits of the MDMSP.

2. The MO has the following responsibilities:
   a) Co-ordination of all meter checking testing, operating and fault resolution processes;
   b) Co-ordination with the related entities to confirm the metered data and the off taken and traded power at the connection points;
   c) Post, with appropriate security measures, the metering data on the official website of the power market serving; and
   d) Keep confidential the metering data that relate to the right of one or many market participants provided by the MDMSP and other entities in line with the rules.

Article 163. MDMSP Rights and Responsibilities

1. MDMSP has the following rights:
   a) The right to appoint the ISP; and
   b) Specify the communications protocol for provision of metering data from local server to MDMSP.

2. The MDMSP has the following responsibilities:
   a) Providing, operating and maintaining the metering equipment at each metering site, from the communications port of the local data acquisition server;
   b) Collect, check, process, archive, and keep confidential the metering data in order to ensure the reliability and accuracy;
   c) Provide the metering data for the MO and other involving entities in line with the relevant contracts;
   d) Be responsible for the adequacy and accuracy of the data collected from the meters installed at the TNO premises to the MDMSP for paying in the relevant contracts;
   e) Organize the metering and data collection and transmission system, from the communications port of the local server, of the TNO and list of the metering

systems;

f) Manage the technical information of the metering systems;
g) Consult, install the hardware system, and establish the software system serving for the collection, processing, archiving and keeping confidential of the metered data, remotely synchronizing meter clocks, from the communications port of the local data acquisition server;
h) Organize and carry out the measures to ensure safety and access decentralization to exploit the metered data for paying in the relevant contracts;
i) Be the communication point, in coordination with the involving entities to ensure the metering data collection system operates stably, safely and reliably;
j) Negotiate specifically the operation responsibility of the entities that share the equipment;
k) Provide the MO the metering data in line with the contracts;
l) Calculate, estimate metering data and provide relevant parties when it is unable to collect data from meter, data is not correct, or data is not appropriate for payment;
m) Organize to compile the procedures of operation management and dealing with faults of the metering data collection, processing, archiving and announcement system; and
n) Manage the grant, amendment, cancellation of the metering points in the metering data collection, processing, archiving system.

Article 164. ISP Rights and Responsibilities

1. ISP has the following rights:
   a) The right to access the communication interfaces of metering equipment in order to carry out its work.

2. The ISP has the following responsibilities:
   a) Investment, operation management, maintenance of the equipment serving for metering data transmission in order to ensure the smooth, reliable and safe operation; and
   b) Preside and in coordination with the related entities to deal with the faults of the equipment in the information system serving for transmission of the metering data.

Article 165. MTSP Rights and Responsibilities

1. MTSP has the following rights:
   a) The right to access metering equipment in order to carry out its work.

2. The MTSP has the following responsibilities:
   a) Check, experiment, calibrate, the meters and other equipment of the metering system in the TNO premises in order to ensure the stipulated technical conditions;
   b) Carry out the sealing measures in order to ensure the metering system is safe. In a special case, the sealing measure can be recommended to improve the reliability and security of the metering system;
   c) Organize the management and keeping the confidentiality of the “setting” password level, be responsible regarding the accuracy and confidentiality of the password;

d) In coordination with the related entities in checking and dealing with the faults of the meter and metering system;
e) Archiving the related documents including: minutes of meter installation, metering equipment calibration, sealing measures;
f) Recommend the measures to finalize and improve the accuracy and reliability of the metering system;
g) When called upon to do so, investigate any alleged metering fault, inaccuracy or dispute; and
h) Carry out metering equipment and systems inspections and tests in such a manner as to satisfy itself that systems are providing accurate information.

Article 166. Auditor

1. The Auditor has the following rights:
   a) Access all MDMSP and TNOs systems in order to carry out audits.

2. The Auditor has the following responsibilities:
   a) Carry out audits of the processes and procedures of the MDMSP and the TNOs to assess accuracy and completeness of processes, when requested by EWRC or a party to this Grid Code.

Section u. Service Providers

Article 167. Service Providers

1. This metering chapter requires the designation of four service providers to support the metering activities covered by this Grid Code.
2. These service providers are:
   a) Meter Testing Service Provider (MTSP);
   b) Metering Data Management Service Provider (MDMSP);
   c) Information Service Provider (ISP); and
   d) Auditor.
3. Prior to the commencement of the SLEM the EWRC will designate parties as suitable to carry out these functions. Only service providers approved by EWRC may carry out these functions.
4. Prior to designating service providers under this Grid Code EWRC will seek applications from relevant parties for each role. Each applying party will provide evidence that it possesses the necessary expertise, experience and infrastructure to carry out the role for which it is applying. EWRC may only appoint parties it considers adequate for the role.
5. Parties trading in the SLEM are to choose service providers approved by EWRC in order to implement the functions required under the Grid Code.

Section v. Metering Principles and Metering Position

Article 168. TNOs Responsible for Meter

The TNOs are responsible for provision, installation and maintenance of metering equipment at the points of connection between the TNO and any Generator, Power Pool Operator, or Connected party.

Article 169. Main and Back-Up Metering

1. At each connection point, the main metering system and the backup metering system should be set up.
2. The main metering system should define accurately and fully the transaction quantity to be the basis for payment via the connection point as well as eliminate the factors that impact the metering results due to the loop circuit structure of the power system.
3. The backup metering system has the following functions:
   a) A replacement for the main metering system and is the basis of calculation of transaction quantity in case the main metering system is operated inaccurately or involved in breakdown; and

b) Checking, monitoring the metering results of the main metering system in cases the main metering system operates normally.

Article 170. Metering Position

1. General principles:
   a) The metering position should be at or right next to the connection point;
   b) In case it is impossible to set up the metering position that is at or right next to the connection point, the Trader, relevant TNO and relevant connected party shall agree on the replacement position. The cost for investment of the metering system at the replacement position should be borne by the relevant TNO and they should agree with the connected party in defining the correlation of energy, and losses between the replacement position with the connection point. These are to be accounted for in trading and payment process; or
   c) In case the metering position does not assure the accurate metering, the connected party, Trader and relevant TNO will mutually agree the calculation method of converting energy to the connection point.
2. Specific cases:
   a) The connection point is inside the TNO assets:
      i) The main metering position is defined at either the circuit breaker (CB) which connects the connected party to the TNO bus bar, or the HV and, if relevant MV, side of the step down transformer and used to deliver the electricity at the connection point, unless there is other agreement between the Trader and connected party;
      ii) The backup metering position is defined at outgoing feeders of the connected party, unless there is other agreement between the Trader and connected party.
   b) The connection point is outside of the TNO assets:
      i) In case the connected party has one line to the connection point and there is no power loop through the bus bar of the connection, the main metering position and backup metering position should be at or next to the connection point unless there is other agreement between the Trader and connected party;
      ii) In case the point of connection has more than 2 lines and there is power loop through the bus bar of the connected party point of connection, the metering position is chosen in comply with the principles in point a), item 2) of this Article.

Section w. Technical Requirements

Article 171. Minimum Configuration

The minimum configuration of a metering system must include:

a) Current transformer (CT);

b) Voltage transformer (VT);

c) Meter;

d) Electric circuit and secondary cable;

e) Data logger and communication equipment;

f) Facility to keep the metering installation secure from interference and seal;

g) And other equipment, terminals, test blocks; and

h) In particular cases, voltage selector, voltage and current checking terminal.

Article 172. Meter

1. A meter shall have following features:

   a) Three phases and four wire type;

   b) Standardized and programmable;

   c) Have multiple tariff features;

   d) Be able to meter active energy and reactive energy for incoming and outgoing energy;

   e) Be able to meter active and reactive energy for four quadrants;

   f) Be able to measure peak power;

   g) Be able to record of total load curve and individual phase load curve;

   h) Be able to connect to computer for local and remote data gathering;

   i) Auxiliary voltage must be supplied from VT voltage wire and able to operate when any one or two VT voltage wire is disconnected;

   j) Secured by multiple password level;

   k) Be able to install secured seal from interference in connection and avoid change settings; and

   l) Be able to store at less 60 days of metering information with interval time not longer than 30 minutes:

      i) Self-check information has to be stored in at least 60 days; and

      ii) Be able to store load curve, load profile, history data at least a quarter of year.

2. Accuracy:

   a) For metering equipment installed prior to this Grid Code coming into force the required accuracy shall be:

      i) Main meters must have accuracy class 0.5 for active energy metering, comply with the requirement of IEC 62053-22 standard; and 2.0 for reactive energy metering, comply with the requirement of IEC 62053-23 standard; and

ii) Check/backup meters must have accuracy class 0.5 for active energy metering, comply with the requirement of IEC 62053-22 standard; and 2.0 for reactive energy metering, comply with the requirement of IEC 62053-23 standard.

b) For any new equipment installed once this Grid Code has come into force the required accuracy shall be:

i) Main meters must have accuracy class 0.2 for active energy metering, comply with the requirement of IEC 62053-22 standard; and 2.0 for reactive energy metering, comply with the requirement of IEC 62053-23 standard; and

ii) Check/backup meters must have accuracy class 0.5 for active energy metering, comply with the requirement of IEC 62053-22 standard; and 2.0 for reactive energy metering, comply with the requirement of IEC 62053-23 standard.

c) By 1 January 2021 or such later date as may be advised from time to time by EWRC, all meters used for metering under this Grid Code must comply with the following accuracy requirement:

i) Main meters must have accuracy class 0.2 for active energy metering, comply with the requirement of IEC 62053-22 standard; and 2.0 for reactive energy metering, comply with the requirement of IEC 62053-23 standard; and

ii) Check/backup meters must have accuracy class 0.5 for active energy metering, comply with the requirement of IEC 62053-22 standard; and 2.0 for reactive energy metering, comply with the requirement of IEC 62053-23 standard.

Article 173. CT

1. General:

a) CT must have secondary coils for measurement only;

b) Nominal secondary current is 1A or 5A: and

c) CT must have positions for sealing on measurement terminal box.

2. Accuracy:

a) For metering equipment installed prior to this Grid Code coming into force the required accuracy shall be:

i) CT used for main metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-1 standard or equivalent standards; and

ii) CT used for check/backup metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-1 standard or equivalent standards.

b) For any new equipment installed once this Grid Code has come into force the required accuracy shall be:

i) CT used for main metering system must have accuracy class 0.2S, comply with the requirement of IEC 60044-1 standard or equivalent standards; and

ii) CT used for check/backup metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-1 standard or equivalent standards.

c) By 1 January 2021, or such later date as may be advised from time to time by EWRC, all CTs used for metering under this Grid Code must comply with the following accuracy requirement:

i) CT used for main metering system must have accuracy class 0.2, comply with the requirement of IEC 60044-1 standard or equivalent standards; and

ii) CT used for check/backup metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-1 standard or equivalent standards.

Article 174. VT

1. General:

a) VT must have secondary coils for measurement only.

b) Nominal secondary voltage is 100V or 110V.

c) VT must have positions for sealing on measurement terminal box.

2. Accuracy:

a) For metering equipment installed prior to this Grid Code coming into force the required accuracy shall be:

i) VT used for main metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-2 standard or equivalent standards.

ii) VT used for check/backup metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-2 standard or equivalent standards.

b) For any new equipment installed once this Grid Code has come into force the required accuracy shall be:

iii) VT used for main metering system must have accuracy class 0.2, comply with the requirement of IEC 60044-1 standard or equivalent standards; and

iv) VT used for check/backup metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-1 standard or equivalent standards.

c) By 1 January 2021, or such later date as may be advised from time to time by EWRC, all VTs used for metering under this Grid Code must comply with the following accuracy requirement:

v) VT used for main metering system must have accuracy class 0.2, comply with the requirement of IEC 60044-1 standard or equivalent standards; and

vi) VT used for check/backup metering system must have accuracy class 0.5, comply with the requirement of IEC 60044-1 standard or equivalent standards.

Article 175. Measurement Circuit

1. CT's and VT's secondary coils of main metering system must not be used for other purposes and totally be independent with check/backup metering system.

2. Secondary wiring must be by the most direct route and the number of terminations and links must be kept to a minimum and there have been a sealing method for sealing all terminals and connections of the secondary wiring. Secondary wiring of main metering system must be separated from other measurement wiring and directly from CT/VT kiosk to meter kiosk, bypass marshalling kiosk. A VT kiosk shall be provided with an MCB for the VT circuit.
3. Cables used in secondary wiring must be adequately mechanically robust to avoid insect or rodent damage.
4. The cross sectional area of the cables used in secondary wiring must be such as to not unduly reduce the accuracy of the measurement circuit.
5. Where there are more than one VT installed at the feeder, it is requested to use the voltage change over scheme and meter must be programmed for recording the changed over time. Terminals of voltage selector switch must be able to be sealed.
6. Secondary burden of CT/VT including meter are not over the nominal burden as appearing on label.
7. The CT used for the check/backup meter and the secondary wiring connected from this CT to the check meter can be used for other measurement equipment and these equipment do not affect accuracy of metering system, and metering system is still secured by the application of the seal system
8. The test block must be installed for using for testing the meter system and must have ability to be sealed.

Article 176. Data Collection System

1. Meters used for energy transaction must have function to read data remotely and be compliant with connection interface and data collecting software standards and procedures of MDMSP as published by MDMSP from time to time.
2. Meters used for energy transaction must have communication port in accordance with IEC61158, interface or Ethernet. Built-in modem must be able to access remotely through communication line.
3. According to the model of data collecting system, the way to transmit metering data, file formats and interface specifications should be as specified by the MDMSP.
4. Data collecting system must include a local computer to read and store metering data. Collected data in local computer must be transmitted to Server as specified by the MDMSP.
5. Communication line could be telephone lines, leased line, computer network (WAN, Internet), wire, optical fiber, power line carrier, wireless (microwave, CDMA, or other applicable data standard). Communication line and protocol must be secured to prevent illegal accesses.
6. Equipment connecting to meter must have built-in surge arrester.
7. Converters, isolators, connection port used for connect to communication network, checking equipment should be located in secure cabinets to manage and protect easily.

8. Prior to start of the SLEM, and periodically as required after that, the MDMSP shall publish their requirements for metering data transmission, data file formats and interface specifications.

Article 177. Seal and Security

1. Whole metering system including terminal boxes, CT, VT, meter, terminals, jumpers, secondary circuit, voltage selector, meter cabinet, communication network must be sealed to prevent illegal access.
2. Meter's firmware must be able to set multiple password levels for different users or administrator.
3. Software used for collecting and transmitting data must be secured by multi-level passwords to ensure the accuracy of data.

Section x. Metering System and Off-take Method

Article 178. Adjustment of Metering Data

1. Where the Metering Point does not align with the Connection Point, then the MDMSP shall apply appropriate adjustment factors to correct the data to make it as though it were measured at the Connection Point.
2. The adjustment factors applied shall be as agreed between the relevant parties in accordance with Article 170.

Article 179. Measured Quantity

The measured quantity for any Market or Bilateral trade will be as calculated by the MDMSP based on the metered data, and any adjustment factors applied according to Article 178.

Article 180. Estimated Quantity

1. It is acknowledged that it may not always be possible to obtain all metered data prior to the deadline for SLEM market settlement. In such cases estimated quantity may be provided to the TNO, or Trader as appropriate, for settlement purposes.
2. The MDMSP will provide the TNO, or Trader as appropriate, of any such estimated quantities at the time it provides the metered data. The MDMSP will appropriately tag all such estimated quantities in the data file provided to the TNO, or Trader as appropriate.
3. Where such estimation has been undertaken all affected parties will use best endeavours to subsequently obtain metering data for the relevant periods.
4. Should metering data subsequently become available for periods where estimated data has been provided then the MDMSP will provide such metered data to the relevant

TNO, or Trader as appropriate. They shall provide the metered data, the relevant periods, and the estimated data it replaces.

5. The updated data shall be used by the MO in any wash-up process it uses for settlement.

Section y. Data Collection, Processing and Archiving

Article 181. General Requirements

1. All the meters with the metering function of the main and back up metering system should be equipped with the remote data reader to read and transmit the metering data to the MDMSP for its inspection and oversight.
2. The remote data reader of the entities should be compatible regarding the connection feature, protocol and the standardize requirements of the remote data collection software implemented at the MDMSP.
3. During the period of operating the SLEM, the MDMSP will operate and maintain the remote data collection system implemented at the relevant TNO site, including the information system connected to read the meter data and the software program.
4. The MDMSP is responsible to carry out the measures to keep confidential the metering data collection, processing and archiving system serving for payment purpose.

Article 182. Functions

The metering data collection and processing system of each TNO and MDMSP should have the following functions:

1. The metering data collection and processing systems of the TNOs:
   a) Collect the metering data: Allow the data held in the meters that are under the management scope of the TNOs to be collected as follows:
      i) Daily automatically at the prior defined time; and
      ii) Manually collect upon request.
   b) Data confidentiality: the raw data after being read and transmitted to the server located at the relevant TNO shall be encoded to avoid illegal modification before being transmitted to the Metering Data Management Service Provider;
   c) Provision for MDMSP access to metering data via two methods:
      i) By MDMSP access to the TNO's local server at the TNO's substation; or
      ii) By MDMSP direct read of meters at the TNO's substation.
   d) Metering data management:
      i) Archive the raw data after being read from the meter;
      ii) Collation, adjustment and addition of the metering data;
      iii) Archiving data after being adjusted.

e) Manage the time, data reading and collection schedule;

f) Manage the metering lists;

g) Manage the user's access:

   i) ID number of the user and system access privilege; and

   ii) Coordination of the user and his data;

h) Manage metering information; and

   i) Manage the declaration of the metering point information and the metering system;

   ii) Manage and oversight the legality of the meter and metering equipment; and

   iii) Parameters and technique database of the metering system and equipment.

i) Manage the metering data processing;

   i) Set up the calculation principles for the collation, processing and replacement of the metering data;

   ii) Plan to collate and process the metering data; and

2. Metering data collection and processing system of the MDMSP;

   a) Metering data collection: Allow to collect the data by 2 separated ways:

      i) MDMSP direct reading of TNO's local server; and

      ii) Direct connection between the meter reading program of the MDMSP and the meters at the TNO's premises to read the data.

   b) There are some possible ways to collect the data as follows:

      i) Daily automatically at the prior defined time; and

      ii) Manually collect upon request.

   c) Synchronize the time with the standard time for all the meters in the system;

   d) Metering data management:

      i) Archive the raw data after being read from the meter;

      ii) Collation, adjustment and addition of the metering data; and

      iii) Archiving data after being adjusted.

   e) Manage the time, data reading and collection schedule;

   f) Manage the metering lists of the market participants;

   g) Manage the user's access:

      i) ID number of the user and system access privilege; and

      ii) Coordination of the user and his data.

   h) Manage metering information;

      i) Manage the declaration of the metering point information and the metering system; and

ii) Parameters and technique database of the metering system and equipment.

i) Manage the metering data processing:

i) Set up the calculation principles for the collation, processing and replacement of the metering data;

ii) Plan to collate and process the metering data; and

iii) Keep the authorized agency informed of the collation result; and

j) Connect; share the data with the MO for market settlement purposes.

Article 183. Audit of MDMSP

1. The auditor will, when requested by EWRC, audit the processes, systems and personnel of the MDMSP to determine if:

   a) All processes and systems are in accordance with this Grid Code; and

   b) The quality of the data provided to the market is appropriate for the market.

2. EWRC will request an annual audit of the MDMSP to determine whether the MDMSP is eligible to continue in its role.
3. For the avoidance of doubt the auditor may sub-contract such audits provided it can show, to EWRC's satisfaction, that the subcontracted party has appropriate expertise.
4. The auditor will publish the results of such audits to all relevant parties.
5. The costs of any such audit will be borne by the MDMSP.
6. Any party may request an additional audit of the MDMSP by the auditor at any time.
7. The party requesting the additional audit will bear the full costs of the audit.
8. The MDMSP is to co-operate fully with all such audits.

Section z. Installation Management

Article 184. Installation Programming and Password Management

After installing the meters, the MTSP, the MDMSP, and the connected party (or parties) at the meter location should carry out the following work:

a) MTSP:

i) Program and install the working parameters of the meter;

ii) Establish and manage the password at the level "Read only", "Time clock synchronizing", "Setting" for the meters;

iii) Provide all involved parties the "Read only" password level for the meters installed at the metering point;

iv) Create a copy of the password level of "Time clock synchronizing", "Setting" enclosed with a list of the corresponding meter, put in a closed envelope sealed by the MTSP and keep these passwords confidential;

v) Provide the MDMSP with the password level of "Time clock synchronizing" for them to carry out the functions of reading the data and meter synchronization; and

vi) Be responsible with connected parties who provided data regarding the confidentiality of the sealed equipment and password level of "setting".

b) MDMSP:

i) Keep confidential the "Time clock synchronizing" password level provided by the MTSP;

ii) Synchronizes the time for the meter clocks during operation;

iii) Be responsible with connected parties who provided data regarding the confidentiality of password level of "time synchronizing clock". MDMSP is not responsible for the confidentiality of the sealed equipment; and

c) TNO and concerned connected parties shall take responsibility for keeping confidential of password level of "Read only".

Article 185. Meter Sealing

1. Before the metering system comes into operation, the MTSP is responsible to seal the meter and the relevant equipment in the metering system. The sealing or unsealing of the metering system is done by the MTSP witnessed by the connected party (or parties), Trader and TNO.
2. Each TNO is responsible to manage their metering system, ensure the sealing is not illegally violated and is also responsible for the management of the meter and metering system sealing.
3. The MTSP is responsible to manage tool of Seal in accordance with Market Rules, or any relevant PPA contracts and Law.

Article 186. Metering Data Reading System

The MDMSP and TNOs are responsible in management of the metering data reading system as follows:

a) The MDMSP:

i) Set up and keep confidential the parameters, install the meter data reading software program at the TNO, and at the MDMSP;

ii) Establish and implement the confidentiality measures for the data transmission system from the meters to the servers located at the TNOs and to the MDMSP to ensure the accuracy and reliability of the metering data serving for payment purpose; and

b) Each TNO, as appropriate, is responsible to keep confidential the installed and set up parameters for the meter data reading software program installed at the TNO. They shall strictly prohibit the interference in the reading and transmission program to modify the installed parameter and the data read from the meter to the server located at the plant and the data transmitted from the server of the plant to the MDMSP.

Section aa. Changes to Metering System

Article 187. Changes to Metering Point

1. In case a new metering point is added or an existing metering point changed, the party requesting the new metering point must announce and come to an agreement with the relevant TNO, connected party and Trader about the metering point and design of metering and data collection systems, and any relevant adjustment factors at this metering point.
2. Where the agreed metering point and the connection point do not align adjustment factors may be applied to ensure metered data aligns with actual electricity flows at the connection point. Such adjustment factors must be agreed as per item 1 of this article.
3. After metering points and design of metering and data collection systems have been agreed upon by the connected party (or parties) and Trader(s), TNO has responsibility for investment, installation of metering equipment, seal, data collection system and has responsibility for:

   a) Ensuring that metering point on location must suit the above agreement of Trader(s), and connected party (or parties);

   b) Ensuring that installation of metering and data collection equipment are as per IEC standards. Installation of Metering and data collection system on location must suit the design as approved;

   c) Combining with meter MTSP to carry out the following:

      i) Ensure that all metering equipment which will be used for the first time must be tested. Programming and installation of the working configuration for the meter in accordance with the process and exact conclusion for metering equipment and metering system; and

      ii) Meter, CT, VT, metering circuit, terminal, marshalling kiosk must be sealed and ensure that security for metering system; and

   d) Combining with MDMSP and ISP to carry out:

      i) Metering data collection equipment and installation configuration of meter must be tested as per IEC standards. Information system is installed, data reading program is built and meter data collection must be secured when it is sent to computer; this computer is put in TNO and MDMSP's charge; and

      ii) Data collection system must be operated and tested.

Article 188. Metering System Acceptance

1. After metering and data collection system installation is completed relevant TNO presides over acceptance and sends plans for acceptance to connected party (or parties), Trader and relevant parties to suggest acceptance of the metering and data collection system.
2. At least 14 days prior to the planned metering acceptance test, a proposed acceptance test methodology must be sent to relevant parties.
3. Prior to the start of acceptance testing each party must send the TNO files confirming: metering and data collection system is installed as per regulations; it is tested and sealed and include all valid reports of testing of the metering equipment.
4. Metering and data collection system acceptance process is to include:
   a) Connected party;
   b) MTSP;
   c) MDMSP;
   d) TNO; and
   e) Trader(s).
5. In process of checking and taking over metering and data collection system, MTSP and MDMSP have the following responsibilities:
   a) MTSP has responsibility for:
      i) Providing test and meter installation reports and level password "read only" about metering data to connected party, relevant TNO and Trader(s).
      ii) Defining security method and seal point;
      iii) Providing level password to synchronize the meter time clock and relevant information metering point to update metering database management program to MDMSP;
      iv) The test reports, documents, parameter of metering equipment and metering system must be stored; and
      v) Level password "Install" of meter must be stored and secured. Responsibility to law for secret level password "Install" is installed for meter and exact data is installed for meter; and
   b) MDMSP has responsibility for:
      i) Providing test reports about data collection system to connected party, relevant Trader(s) and relevant TNO;
      ii) The test reports, documents, parameter of metering data collection equipment must be stored; and
      iii) Responsibility to market participants for metering data collection must be exact
6. Result of acceptance metering and data collection system is confirmed by acceptance and meter data writing reports at the time acceptance according to form. Relevant TNO

has responsibility for storing copies of all documents of metering and data collection system and distributing copies to all relevant parties. Documents required include:

a) Technical documents;

b) Test reports; and

c) Acceptance reports.

Article 189. Working Configuration Replacement

Metering equipment and installation of the working configuration replacement process will be:

a) The relevant TNO must announce the proposed replacement and come to an agreement with connected party (or parties) and Trader on the details of the proposed replacement;

b) MTSP carry out and record the report of installation and test. In the process, it must be witnessed by representatives of the MDMSP, connected party (or parties), TNO and Trader(s); and

c) The relevant TNO has responsibility for assembling report and providing to relevant parties and market operator within 2 business days since the time of modification has been done.

Article 190. Metering Point Removal

1. In case one or numerous metering point of a TNO, is removed with reason for connection of wires, structure of equipment, mode of operation is changed, electricity trading is calculated by other method or other reasons, the relevant TNO must announce to the connected party and all relevant parties about the metering point removal plan, and agree with relevant parties how electrical energy will be calculated after metering point is removed.
2. Once agreement is reached then at least 14 days before plan is carried out, advice of the change date must be sent to relevant parties.
3. The relevant parties to this process are:

   a) Connected parties;

   b) TNO;

   c) Trader(s);

   d) MDMSP; or

   e) MTSP, in case of metering system must be tested before metering point is removed.
4. While removing a metering point, participants must carry out the following process:

   a) In special case, at the time before metering point is removed, participants can request for testing about operation of metering system;

   b) At the time of the metering point removal, meter data must be recorded; and

c) The TNO must provide a report about metering point removal including information on:

i) the metering point removed,

ii) the time of official metering point removal,

iii) Confirmation that all work was completed according to above regulation; and

iv) Confirmation report must have seal and signed by delegate of relevant parties.

5. TNO, has responsibility for sending result of metering point removing and relevant documents to MDMSP to update into database and collection, analysis and store metering data to serve operation and settlement in power market.

Article 191. Metering System Information Management

1. The TNO and MDMSP jointly have responsibility for management of information relating to the metering system, which includes:

a) The drawing determining metering points;

b) Completed drawing of metering system diagram installation;

c) Metering point code, name of metering point, date of commencement;

d) Parameter of meters, CTs, VTs of main and backup metering systems, including:

i) Serial number of meter, CT, VT;

ii) Identification name of meter, VT, CT;

iii) Equipment types and models of meter;

iv) Ratios of VT, CT, coefficient of meter;

v) Test reports of meter, VT, CT;

vi) Installation report of meter;

vii) Sealing method used for the meter and metering system; and

e) Data communication details, including:

i) Telephone numbers and code of meter for access to data;

ii) Communication equipment type and serial numbers;

iii) Communication protocol details;

iv) user identification and access rights; and

v) Installation password (to be contained in a hidden or protected field).

2. Each TNO has responsibility for providing metering system information management and detail information for MDMSP to update into database and collection, analysis and store metering data to serve operation and settlement in power market.

Section bb. Metering System Operation

Article 192. Operation of Metering System

1. Each TNO, has responsibility to manage, supervise; maintain; replace its metering system in order to assure accuracy, stability, confidence and security in operation of this system.
2. For ongoing management and operation, each TNO has responsibility to supervise, check frequently the operation of its metering system for detecting abnormality or failure of metering system. In case of abnormality or failure of metering system, relevant TNO, must announce immediately to connected party (or parties), Trader(s) and relevant entities, and co-ordinate with them for resolving this problem. Failure resolving process will comply with Article 194. The replacement of an equipment or technology applied to the metering equipment, operation and settlement processes will only be implemented if agreed between the connected party, TNO and the Trader(s); and obeyed procedures set out in Article 189 of this Grid Code.
3. Seal on equipment of metering system will only be removed in case of audit, testing and failure resolution conducted by MDMSP under the eyewitness of authorized representative of buyer and seller.
4. The time clock of the meter and the data collection equipment will be synchronized to the Sierra Leone official time. The metering data will be collected from metering points with the integrated period of 30 minutes and accuracy of ±5 seconds in comparison with the Sierra Leone official time. The official time is original from Global Positioning System (GPS).
5. The accuracy of the meter and metering equipment will be maintained corresponding with accuracy class standard.

Article 193. Periodic and Unexpected Testing

1. Each TNO, has responsibility to conduct commissioning test, acceptance test of equipment installation, conduct periodic audits, check measurement circuit and resolve failure of equipment of its managed metering system.
2. Periodic testing of metering equipment will be periodically implemented: every one (1) year for meter; period of current transformer and voltage transformer testing may be synchronous with period of integrated equipment overhaul, but not greater than five (5) years per time.
3. MTSP has responsibility to conduct the periodic testing. Authorized representative of connected party, TNO and relevant Trader(s) will oversee testing process.
4. Proposed testing plan must be sent to all relevant parties before 10 working days. After periodic testing plan is finished by MTSP and relevant TNO, the connected party and relevant Trader(s) will be notified by writing at least 14 days before the day of periodic testing, and connected party will reply relevant TNO, within 7 days.

5. In case meter, current transformer and voltage transformer are not tested in right period set out in this article, connected party and relevant Trader(s) have right to refer the matter to the industry dispute resolution body for investigation.
6. Connected party, relevant TNO and relevant Trader(s) have right to request additional testing of equipment and metering system at any time in interval between two continuous testing times:
   a) Testing follow request of connected party: Connected party will notify to relevant TNO and Trader at least 7 days before testing day, only implement the testing after received the acceptance writing of relevant TNO and Trader. Connected party, will pay fees of the testing services; and
   b) Testing follows request of relevant TNO or Trader: Relevant TNO or Trader will notify the connected party, at least 14 days before testing day and will only implement the testing after receiving the acceptance, in writing, of the connected party. Costs for such testing shall be allocated as follows:
      i) If metering system determines any error which is over the acceptable limits, the relevant TNO must pay for all irregular testing fee; or
      ii) If metering system's error is still within the acceptable limits, connected party who requests testing will pay for that irregular testing fee.
7. If the testing results represent that accuracy of metering equipment is out of permitted range, this equipment will be corrected, repaired or replaced as soon as possible; and will be retested or certificated (in case of new replacement) by MTSP before it functions. Relevant TNO will pay all relevant cost.
8. If the audit of MTSP may cause the possibility of influencing data gathering of MDMSP, MTSP must submit audit solutions to MDMSP in prior. The audit can only be implemented if the audit solution was agreed by all parties.

Article 194. Fault Resolution

1. Any entity that detects defective or failure of metering equipment or system will notify TNO for them to coordinate the resolution process. Time for resolving failure of metering system, including detection time, is not more than 2 days, except in situation where exists the agreement between connected party and relevant TNO.
2. In all cases, except for emergencies set out in Clause 3 of this article, the failure resolution process requires participation and eyewitness of connected party and Trader(s) representative. The failure resolution process will be recorded in written form, including the signature of all participating persons; after that, this report requires the signature and seal of the authorized representative of the relevant entities.
3. In case of emergency, if failure on metering system may endanger human life or equipment, relevant TNO will be permitted to self-resolve this failure, but also notify immediately to connected party and relevant Trader and make a report about detail information of failure and resolving measure, such as: time of failure, failure status, time for resolving failure, data of meter before failure and after failure resolving. Report requires seal and signature of authorized representative of connected party and

Trader. After that, relevant TNO, co-ordinates with connected party, relevant Trader(s) and relevant entities to implement the seal process and determine any adjustment for energy quantity.

4. Adjusting energy quantity in the time of metering system fail will be calculated and accepted by both the connected party, and the relevant Trader using the methodology developed under Article 197.
5. Where estimated metering data has been provided then the procedures of Article 180 will apply.
6. Report of calculation and confirmation of adjusting energy quantity within interval of failure of metering system require seal and signature of authorized representative of connected party and Trader(s). Relevant TNO, will send data of adjusting energy quantity to MDMSP for updating MDMSP's database and input data of settlement software.
7. Connected party, and relevant Trader will use the metering result, calculated, adjusted and accepted by the relevant parties, to determine the payment for each interval of non-correct metering. Any relevant party, that does not accept this metering result, will notify industry dispute resolution body for resolving measure.
8. In case of burn-out of a metering equipment or no reading by the metering equipment, relevant TNO is responsible for repairing or replacing it as soon as possible to assure that the equipment satisfy technical requirements and function normally. Repairing and replacement of equipment will be implemented following terms of Article 189 of this Grid Code. To resolve quickly the failure of burnt out meter, each TNO must have spare meters for all type of its functioning meters. The spare meter will be tested in advance and stored in technical conditions set out in relevant regulations.

Section cc. Data Acquisition and Management

Article 195. Operation

1. Each TNO has responsibilities to manage and operate its metering data collection and management system in order to ensure completely and accurately updating data from power meters which are under the management by themselves to the central computer locating at the TNO's facilities and from that to the MDMSP. The metering data then will be updated to database system of the power market.
2. MDMSP has responsibilities to fully, precisely, securely manage and operate power metering database and acquisition, process and record program. The metering data collected must be stored for at least 5 years.
3. ISP has responsibilities to manage and operate, maintain information links from TNO's facilities to MDMSP in order to ensure readiness, stability and reliability of the data reading and transmitting process between MDMSP and TNO.

Article 196. Data Validation

1. As part of its process for collecting metering data the MDMSP will undertake reasonable checks of received metering data to confirm it is valid data. They shall do so using the data validation procedures developed under Article 197.
2. Where the MDMSP considers the metering data is outside expected range, or may be invalid for some other reason, it shall investigate and attempt to resolve the problem as soon as practical.
3. If it is unable to obtain valid metering data before the deadline for provision of metering data for settlement it may substitute estimated data using the procedures developed in Article 197, and following the process for use of estimated data as per Article 180.

Article 197. MDMSP to Develop Operational Procedures

1. The MDMSP has the responsibility to develop and publish the following procedures prior to the start of the SLEM:
   a) Time synchronisation procedures for meters;
   b) Data validation procedures for metering data;
   c) Data estimation procedures for missing metering data; and
   d) Data interface standards.
2. The MDMSP shall consult all affected parties in developing these procedures and seek their input to the procedures.
3. Key principles for each procedure are:
   a) Time synchronisation procedure:
      i) This procedure shall aim to ensure all meters work to a common time basis; and
      ii) Procedures will include processes for correcting metering data when time synchronisation exceeds a reasonable threshold.
   b) Data validation procedure:
      i) This procedure shall aim to ascertain the meter data is within expected range and flag any out of range values for further investigation;
      ii) It shall identify any zero readings for further checking;
      iii) It shall identify any readings where the metered value exceeds the rating of the primary plant being metered; and
      iv) It shall compare main and back up metering, where available, to see if differences are within tolerance.
   c) Data estimation procedure:
      i) This procedure shall aim to estimate missing data with a reasonable degree of accuracy;

ii) Using metering data of the first level backup metering system to determine the error of main metering system in the time of main metering system failure or its error is larger than the accuracy class;

iii) In case first level backup metering system fails or its error is larger than the permitted values, transaction energy will be determined by:

(1) In case of main metering system records metering data but with unpermitted error, transaction energy is equal to metering data converted to 0% error;

(2) In case of metering data is not recorded by main metering system, relevant parties will do an agreement on the method for calculating adjusted energy transaction in interval of non-correct metering based on failure status and real error of metering system in report of testing agent and results accepted by relevant parties;

(3) Using metering data of the second level backup metering system to determine transaction energy in the intervals when the main and first level backup metering systems are in problem. In this case, relevant parties will jointly calculate losses in transformer and auxiliary energy and convert this metering data from installed point of second level backup metering system to point of main metering system;

(4) Determine based on hourly average capacity at metering point written in operation diary; or

(5) Other method accepted by relevant parties.

iv) If the above is not possible then quantity of energy in interval of failure of metering system will be determined based on contracted energy for that location for that period.

d) Data interface standards and procedures:

i) This procedure will aim to specify the interface parameters to allow the MDMSP to remotely read data from the TNO's meters and metering equipment;

ii) It shall use industry standard interfaces and procedures where possible;

iii) It shall aim to accommodate existing metering arrangements by TNO where practical; and

iv) It shall aim to maximise the reliability and integrity of the data transfer process.

Article 198. Rights of Access to Metering Data

1. Connected parties and relevant Trader(s) have right through the password level "Read only" to read data of power meters, which are installed in their managed area.

2. MDMSP has right through the password level "Synchronizing time clock" to connect and read measuring data as well as synchronize the time of power meters of every TNO meter covered by this Grid Code.

Article 199. Rights of Management of Metering Data

1. MDMSP is in charge of creating, managing the measuring system as well as updating, checking and securing database and acquisition, process, storage program of power procurement, settlement data of generation units participating in the power market.
2. The Trader(s) has rights to access, exploit database and power procurement, settlement data collective program of generation units participating in the power market, for which it has contracts with.
3. Connected parties have rights to access, exploit measuring data of all power measuring of their own positions.

Article 200. Access and Transfer of Metering Data

1. Access mode of metering data:
   a) Metering data of each TNO meters to MDMSP will be accessed on a daily basis by 2 parallel and independent modes:
      i) Mode 1: Each TNO will access data of its meters and transfer to its server computer. After that, this data will be automatically transferred to MDMSP; and
      ii) Mode 2: MDMSP: MDMSP connect directly to meter to read metering data and synchronize time clock every meters
   b) Metering data access and meters time synchronisation will be daily implemented by each TNO and MDMSP, and day-before metering data must be completely transferred to MDMSP before 7 hours of day-ahead. MDMSP will co-ordinate with each TNO in planning of metering data access to avoid the accessing and transferring congestion of metering system;
   c) Each TNO is responsible for daily checking and monitoring its data access system to ensure that metering data will be complete and precise transferred to its server computer and to MDMSP. In case of being impossible to access or transfers metering data, including the case of late transfer (caused by default or any reason) in any transferring method (e-communication, telephone, fax), TNO will notify MDMSP immediately; and
   d) MDMSP has responsibility to check completion and correction of metering data received from meters of each TNO. After accessing and checking completion and correction of metering data received from meters of each TNO, MDMSP will send to relevant trader(s).
2. Meters data access:
   a) Meters data accessed by each TNO and transferred to each TNO's server computer and to MDMSP, include:
      i) Daily accessing data, including generated/consumed active and reactive energy in 30 minutes intervals of main and backup meters of TNO; and

ii) Monthly accessing data; including the meters data fixed at 0 hour 00 of the first day of month saved in total records and tariff of generated/consumed active and reactive energy record of all TNO's main and backup meters.

Article 201. Check and Comparison of Metering Data

1. Check and comparison of metering data is in order to confirm the correction and correspondence between metering database of MDMSP and data recorded in meters of each TNO, and is the basis of the issuance of invoice to settle traded energy.
2. MDMSP has responsibility to check and compare metering data. Recorded metering data will be the base to settle the energy traded between relevant parties, and its correction and confidence will be checked basing on:
   a) Backup meters data of each TNO will be used to compare with main meters data of the relevant TNO and will be base to confirm correction and confidence of that TNO's metering system in operation;
   b) Metering data accessed by each TNO and transferred to MDMSP will be compared with metering data accessed directly by MDMSP to confirm the correction and confidence of data; and
   c) Data of the Monthly energy of each meter is the total of energy quantities recorded within 30 minutes of the total number of days in the Month, and will be compared with energy data measured by this meters and fixed from 0 hour of first day of the Month to 24 hour of last day of the Month.
3. In case of arising the difference between meters data and data in TNO's server or in database of MDMSP:
   a) Relevant TNO will have overall responsibility for meter fault resolution;
   b) Relevant parties, including connected parties, MDMSP, relevant TNO will co-ordinate to determinate cause of error; propose and agree measures for correcting this error; and
   c) Meters data will be principal base for determination of energy quantity transmitted through metering point.
4. Within 6 days from the day when metering data is made available to connected party and relevant Trader, the connected party and relevant Trader have responsibility to check and compare metering data. In case of non-agreement of this data, market participant has right to request MDMSP to conduct the data checking and comparison for confirmation of data correction; or for detecting error origination and correcting this error if any.
5. In case results of data checking and comparison present the correspondence between data recorded in meter and in database of MDMSP, but the relevant parties do not agree with this data, relevant TNO has responsibility to check its metering system. Checking process comply with procedure set out in Article 193 of this Grid Code.

Article 202. Resolving Failure of Metering System

1. In process of managing, operating , and supervising data acquisition system, if any connected party recognizes any error or failure in data reading and transmitting system which may cause the accessibility of data can not be achieved remotely, that connected party must notify MDMSP immediately to resolve. After receiving the notification, MDMSP is responsible to contact with concerned entities which are the connected party, Trader, relevant TNO, MTSP, and ISP and carry test promtly, determine the fault and suggest repairing method.
2. After the detection of failure, asset owner will be responsible for resuming normal function of data acquisition and management system in case its managed equipment for data acquisition and management system fail (in accordance with Section y of this Chapter).
3. After the restoration of data acquisition and management, relevant TNO, and MDMSP are responsible for conducting meters connection procedure in accordance with Article 200 of this Grid Code to collect metering data within interval of metering system failure.
4. In case of being impossible to resolve failure in time, relevant TNO, has responsibility to collect meters data directly through optical port or IEC61158 port and send this data (by email, file) to MDMSP for updating database of metering system.
5. In case of failure of meters or metering system that cause the impossible or error of data access, MDMSP will co-ordinate with relevant parties to update metering data for resettling, or to upgrade metering database and input data of settlement calculating program. Procedure of co-ordination among relevant parties to resolve failure of meters/metering system is set out in Article 189 of this Grid Code.

Section dd. Confirmation of Metering Data

Article 203. Meter Data Reading and Confirmation

1. On the first day of every Month, TNOs have responsibility to co-ordinate with Trader(s) and connected parties on meters data finalisation and confirmation of Monthly energy quantity at main and backup metering point. Meters data is fixed at 0 hour 00, the first day of every Month.
2. Finalised data of meter and measured energy data at each metering point will be included in a confirmation report and will be confirmed by representative(s) of relevant connected party, and Trader(s). The confirmation report must include the signature and seal of representative(s) of two parties.
3. At the latest on the second day of every Month, TNOs, have responsibility to send confirmation report(s) to MDMSP. MDMSP check, compare data in report and send to Trader(s) for upgrading Monthly power settlement.

Article 204. Responsibility for Data Confirmation

1. Before the 4th day of every Month, MDMSP has responsibility to report hourly energy quantity of each connected party that is included in the collected data from metering data collection by TNOs. Data will be checked and confirmed in accordance with Article 201 of this Grid Code to assure correction and correspondence with data written in report confirmed by relevant connected party and relevant Trader in accordance with Article 203 of this Grid Code.
2. Report, set up in Clause 1 of this article, must include signature of representative(s) of relevant Connected party and relevant Trader(s), MDMSP, then send to relevant Trader for settlement between connected party, and relevant Trader.

Article 205. Energy Data File for Market Settlement.

Energy data file for market settlement, including the confirmation report(s) between relevant parties in accordance with Article 203 and Article 204 of this Grid Code, will be a part of settlement file. The MDMSP is responsible for sending this file to the MO in a format and to a timing to be advised by the MO.

THE DISTRIBUTION SUB – CODE

Chapter XI. Connection to the Distribution Network

Section ee. Objectives and Scope of Connection to the Distribution Network

The objectives of this section on Connection to the Distribution Network are to:

(1) Specify the fundamental procedures and rules for connecting to the distribution network.

(2) To guarantee the non-discriminatory treatment of distribution network users

(3) To state the technical requirements for the safe and reliable operation of the distribution network

Article 206. Scope of Application

(1) This chapter on the Distribution Network shall apply to all users of the distribution network including:

(a) DCs

(b) Embedded Generators

(c) End-use customers

(d) Generators

Section ff. Distribution System Connection Process and Procedures

Article 207. Connection Arrangements

(1) Applicants who want to make a new connection to the distribution network shall make an application to connect to the distribution network to the DC operating the said network.

(2) The DC shall provide an application form for the purpose

(3) Applicants seeking connection at MV and HV levels are required to avail information on fluctuating loads, capacitor banks and rectors that might affect distribution network performance.

(4) Upon the receipt of an application, with full information, for connection to its distribution network, the DC shall comply with all requirements relevant to the connection process as specified in this Grid Code.

Article 208. Application for Connection

(1) Upon the receipt of an application for connection to its distribution network the DC shall make the necessary assessment of the application submitted and advise whether the applicant can be connected to the distribution network or what improvements, technical or otherwise, that will be required for the applicant to be able to connect to the distribution network.

(2) Where the DC is satisfied that the applicant has met all the requirements to be connected to the distribution network, it shall make an offer to connect in writing to the applicant, who can accept such a connection offer in writing before both parties shall enter into a connection agreement.

(3) Subject to (2) above, the DC shall prepare and make available its offer to connect to the applicant within a period of 10 days for MV customers or 21 days for HV customer, unless otherwise agreed by the parties.

(4) The DC's offer to connect to its distribution network shall be fair and reasonable and may state other available options that the applicant can explore.

(5) Such a connection agreement, as in (2) above, shall contain, but not limited to the following:

a. Project planning data,
b. Inspection, testing and commissioning programs
c. Electrical diagrams, and
d. Any other information the DC considers relevant for the processing of the connection application.

(6) Where the DC rejects the application for connection to its distribution network, the applicant shall be advised of the possible remedial measures to be undertaken for the application for connection to be acceptable.

(7) Where the applicant does not accept the DC's offer to connect and, as such, could not reach an agreement with the DC on the anticipated connection, a dispute

resolution process as outlined in Chapter XVII of this Grid Code will be adhered to by the parties.

(8) During this process of application for a connection to the distribution network, all negotiations that might take place between the parties shall be done in good faith and all information provided shall be considered confidential by both parties.

Section gg. Responsibilities of the DCs

Article 209. General Responsibilities of the DCs

(1) The DC shall make available capacity on its distribution network and provide open and non-discriminatory access for the use of this capacity to all customers connected to its distribution network. The DC shall be entitled to a fair compensation for the provision of this service through electricity tariffs as determined through a tariff process stipulated in the Commission's Tariff Rules, 2019 and approved by the Commission.

(2) The DC shall make its Customer Connection Charter available to its customers. The content of the charter shall include, but not limited to, the following:

a. The specific DC's connection / supply application process and all the steps to follow for all customer categories
b. The specific DC's information requirements from the customer to make an appropriate connection.
c. Related timeframes for the various processes which follow the application for connection / supply for all customer categories.

(3) The DC shall respond to the customer's request for connection within the period as specified in the Electricity Distribution and Supply (Consumer Service) Regulations, 2019.

(4) The DC and the customer shall sign a connection agreement prior to the actual connection to the DC's distribution network.

(5) The DC shall advise potential customers of the status of its distribution network and its expected reliability upon a written request.

(6) The DC may participate in the final inspection and testing of customer's equipment and facilities to be connected to its network prior to any connection to its distribution network.

(7) The DC shall maintain its distribution network in accordance with good industry practice and this Grid Code.

(8) The DC shall be responsible for the planning, design and engineering specifications of the work required for the connection to its distribution network or expansion of the same.

(9) The DC shall conduct Distribution System Impact Assessment studies to evaluate the impact of additional loads or an embedded generator or major modification to its distribution network. The assessment conducted shall include the following where relevant:

a. Voltage impact studies
b. Impact on network loading
c. Fault currents
d. Coordination of protection systems
e. Impact on the system's quality of supply
f. Strengthening of the system

(10) The DC shall refuse the connection of any facility or customer equipment which the Distribution System Impact Assessment studies indicate will have a detrimental effect when connected to its distribution network.

(11) The DC may request the customer to submit design information, drawings or other relevant information to the DC if it believes any proposed installation of equipment or facilities or modification of its current facilities has the potential to adversely or materially affect the performance of its distribution network.

(12) Wherein the results from the Distribution System Impact Assessment Studies carried out for a proposed new or modified facility or equipment owned, operated or controlled by the DC or any other customer on the distribution network indicate the possibility of any material effect at the point of connection, the DC shall alert all affected customers prior to commissioning of the facility or equipment.

(13) The DC shall make available, on a request from a customer, design information, drawings or any other relevant information of the existing or proposed distribution layout.

(14) The DC shall connect an Embedded Generator in accordance with the requirements of Section kk.

(15) All employees or agents of the DC shall comply with the customer's safety requirements when entering or accessing premises or facilities of the customer.

Section hh. Responsibilities of Customers and / or Users of the Distribution Network

Article 210. Customers / Users Responsibilities

(i) Customers shall ensure that it provides safe access to the DC's employees to carry out installation, operation or maintenance of the DC's electrical equipment located within the customer's premises.

(ii) Customers shall ensure that there is no unreasonable delay to grant access to the DC's equipment located within the customer's premises.

(iii) Customers shall be responsible for the removal and the reinstallation of any privately owned equipment for the DC to perform the installation work that the customer has requested.

(iv) Customers (excluding residential and domestic supplies) shall, prior to commissioning, attempt to identify if new or modified equipment owned, operated or controlled by the customer could have a detrimental or damaging effect at the point of connection. The customer shall advise the DC should such detrimental or damaging effect be identified.

(v) Where the customer believes an existing, or planned DC installation has the potential to adversely or materially affect the performance of the customer's plant, the customer may request the DC to submit design information, drawings or other relevant information.

(vi) Customers shall also comply with any reasonable additional requirements specified by the DC in respect of the technical and design requirements of equipment proposed to be connected to the DC's distribution network.

Section ii. Distribution System Technical Requirements

Article 211. Protection Requirements

(i) The DC's network protection system shall be aptly designed, coordinated and maintained to guarantee safety, optimal discrimination and minimum interruptions to its customers.

(ii) The customer shall install and maintain protection equipment that is compatible with the existing distribution network protection. The customer's protection settings shall ensure coordination with the DC's protection equipment.

(iii) The customer shall, on a written request, make available to the DC the test certificate(s) of its protection system(s) that are installed at the point of interface with the DC's network prior to the commissioning of its system.

(iv) Customer's or Embedded Generator's protection system shall, where relevant, make provisions to safeguard their own equipment from faults or conditions that may occur at the point of connection with the DC's network including loss of one or two phases of the three phase supply and low voltages on the phases and any auto-reclosing or sequential switching features that may exist on the distribution network.

(v) Wherein protection schemes have been shared, the parties shall provide the necessary equipment and interconnection to the equipment of the other party.

Article 212. Quality of Supply

(i) The DC and other distribution network participants shall comply the Chapter III of this Grid Code regarding the parameters listed below:

a. Voltage harmonics and inter-harmonics
b. Voltage flicker
c. Voltage unbalance
d. Voltage dips
e. Interruptions
f. Voltage regulation
g. Frequency

h. Voltage surges and switching disturbances

(ii) Other special quality of supply criteria can be agreed upon between the DC and any Embedded Generator within its distribution network.

Article 213. Load Power Factor

(i) Customers, apart from Embedded Generators, with demand exceeding 100 kVA shall ensure that the power factor (cos φ) shall not be less than 0.95 lagging nor shall it go leading unless otherwise agreed to with the DC.

(ii) Wherein the power factor falls below the set limit, corrective measures shall be taken by the distribution network users within reasonable timeframe to resolve the situation.

(iii) Customers aiming to install shunt capacitors or any other equipment geared towards complying with these power factor requirements shall notify the DC in writing.

Article 214. Earthing Requirements

(i) The DC shall advise customers about the neutral earthing methods used in its distribution network as and when requested.

(ii) The neutral earthing method employed on the customer's installations that are physically connected to the DC's network shall comply with the DC's relevant earthing standards for loads and for Embedded Generators.

(iii) Protective earthing of equipment must be done in accordance with the relevant international standard.

(iv) Wherein the calculated Ground Potential Rise, as calculated based on IEEE Std. 80-2000, exceeds 5 kV, the responsible party shall inform the affected network participants.

(v) Approved lightning protection requirements shall be applied to the distribution network and all switching yards.

(vi) Substation earthing requirements shall be in accordance with IEEE Std. 80: IEEE Guide for safety in AC substation grounding.

(vii) substation grounding

Article 215. Distribution Network Interruption Performance Indices

(i) The Commission will from time to time set the format for reporting Distribution Network Reliability Indices.

(ii) The DC shall publish its targets for reliability of supply for the next year before the 15th day of December every year.

(iii) The Commission shall evaluate the Distribution Network Reliability Indices annually to compare the DC's actual performance with the DC's specific targets set by the Commission and these comparative analysis will be published.

Article 216. Losses in the Distribution System

(1) Losses shall be classified into three categories:

a. Technical Losses

b. Non-Technical Losses and

c. Commercial Losses.

Article 217. Equipment Requirements

(i) All equipment located at the connection point between the user and the distribution network shall be in compliance with the prevailing national standards or the prescribed standards set by the DC.

(ii) The customer shall make a written request to the DC for all the necessary information needed for the installation of equipment, indicating the rating and capacity.

(iii) The DC is shall provide the customer with such information as requested by the customer to enable the installation of its equipment.

(iv) All equipment at the connection point shall be maintained in accordance with the manufacturer's specifications or an alternate industry recognised methodology and this shall be the responsibility of the relevant customer / Embedded Generator and the DC.

(v) All test results and maintenance records relating to equipment at the connection point for MV and HV connections shall be retained by the relevant parties and made available upon request.

Section jj. Distribution System Planning and Development

Article 218. Framework for Distribution Network Planning and Development

(1) During the process of Distribution Network Planning and Development, the DC shall make use of relevant data from relevant source such as:

a. National Integrated Resource Plan,

b. Integrated Development Plan,

c. customer information,

d. system performance statistics,

e. Distribution network load forecast, and

f. government and customer development plans

to establish the need for network strengthening.

(2) The DC shall compile a 5-year load forecast on an annual basis at its incoming points of supply including any of its cross-boundary connections.

(3) The DC shall compile and submit its network development plans every 5 years and the plans shall be reviewed at least every 3 years. The network development plans shall ensure a capable network and as such shall include all relevant activities such as electrification and refurbishment. These plans shall be prepared only taking into account the available information. All unexpected loads or customer requests shall be added to the plan in retrospect.

(4) All network development plans and post release modifications shall be submitted by the DC to the Commission upon a written request.

(5) The DC shall make available its network development plan to its MV and HV customers upon a written request.

Article 219. Network Investment Criteria

(1) Distribution tariffs shall allow for necessary investments to be carried out in the network to ensure the viability of the networks.

(2) The DC shall make the investments specified in its latest tariff submission as and when the required development meets the technical and investment criteria specified below.

(3) Investments must be based on technical reasons and all investments must be the least life-cycle cost technically acceptable solution, and shall provide as a standard:

a. Minimum quality requirements as specified in this Grid Code
b. Minimum reliability and operational requirements as determined by this Grid Code and from time to time by the Commission

(4) All investment choices must be justifiable by considering the technical alternatives on a least life-cycle cost approach. Least life-cycle cost is the discounted least cost option over the lifetime of the equipment, taking into account the technical alternatives for investment, operating expenses and maintenance.

(5) The calculations submitted to justify investments shall assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

(6) The Commission shall approve the determination of the following key economic and financial parameters:

a. Discount rate
b. Customer interruption cost or cost of unserved energy
c. Other tariff and additional economic parameters

Article 220. General Investment Criteria

(1) All investments must be prudent as a least life-cycle cost solution after taking into account, where applicable, alternatives that consider the following:

a. The investment that will minimise the cost of the energy supplied and the customer interruption cost (cost of unserved energy).
b. Current and projected demand on the network.
c. Reduction of life-cycle costs e.g. reduction of technical losses, operating and maintenance costs, etc.

d. Current condition of assets and refurbishment and maintenance requirements.

e. Demand and supply options.

f. Any associated risks.

(2) Shared network investments shall be evaluated on the least life-cycle economic cost. The economic cost will consider the least life cycle total cost of the electricity related investment to both the DC and the customer.

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

(4) The DC shall evaluate investments in terms of the following categories:

a. Shared network investments

b. Dedicated customer connection investments

c. Statutory investments

d. Cross-border connections investments

Article 221. Least economic cost criteria for shared network investments

(1) Shared network investments shall be:

a. Investments on shared infrastructure (not dedicated) assets.

b. Investments required to provide adequate upstream network capacity.

c. Investments required to maintain or enhance supply reliability and/or quality to attain the limits or targets, determined in Quality of Supply of this Chapter, on existing network assets.

d. Refurbishment of existing standard dedicated connection assets.

(2) All shared network investments are to be justified on least economic cost. In determining the least economic cost for shared network investments, the investment must be justified to minimise the cost to the electricity industry as a whole and not just to the DC.

Article 222. Least life cycle cost criteria for standard dedicated customer connections

(1) A standard connection is defined as the lowest life-cycle costs for a technically acceptable solution.

(2) Dedicated customer connections shall be:

a. New connection assets created for the sole use of a customer to meet the customer's technical specifications.
b. Dedicated assets are assets that are unlikely to be shared in the DC's planning horizon by any other end-use customer.

(3) All dedicated connection investments shall be justified on the technically acceptable least life-cycle costs.

(4) Where the investment meets the least life-cycle cost, the customer shall be required to pay a standard connection charge as determined by the Commission from time to time.

(5) Wherein the investment is to be made to serve a customer grouping or a specific group of customers, upon the approval of the Commission, the investments shall be justified collectively as per customer grouping and not per customer.

(6) The DC shall renovate / change / reconfigure all equipment in use to meet standard supply criteria at no cost to the customer and this will be recovered from the use-of-system charges (network "service" charges). This shall be a non-discriminatory approach where no consideration will be given to the special or unique requirements of the customer.

Article 223. Investment criteria for premium customer connections

(1) The DC shall investigate these additional requirements and shall provide a least life-cycle cost solution.

(2) If the customer agrees to the solution, all costs to meet the customer requirement in excess of what is considered the least life-cycle cost investment is payable as a premium connection charge by the customer as determined by the Commission from time to time.. Such costs shall be appropriately pro-rated, if a portion of the investment can be justified based on improved reliability or reduction of costs.

(3) The refurbishment of identified premium connection assets will occur when the equipment is no longer reliable or safe for operation. The DC must justify the need for refurbishment of the premium assets to the customer, and the customer must agree to the continuance of the premium supply.

(4) At the time of refurbishment, if the customer have any additional requirements that cannot be met in terms of the Article 222 (5), any additional investment will be seen as a premium connection.

(5) Where the refurbishment of a supply in accordance with current technical standards will result in additional cost to the customer, an engineering solution that minimises the sum of the DC's and the customer's costs will be found. This least economic cost option will be implemented but any expenditure in excess of the DC's least life-cycle cost solution (as per Article 220 and Article 222 (5) above) will be borne by the customer through a new premium connection charge and shall not be recovered through use-of-system (network) charges.

Article 224. Statutory or strategic investments

(1) DCs shall be obligated to make the statutory investments listed in (3) below.

(2) Statutory and strategic investments will be motivated on a least economic cost basis, as defined in Article 221 above.

(3) Strategic and statutory projects include the following:

(a) Investments formally requested in terms of published government policy but not considered dedicated customer as under Article 222.

(b) Projects necessary to meet environmental legislation.

(c) Expenses to satisfy the requirements on the DC to comply with any health and safety regulations or laws, as approved by the Commission; this is primarily to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity distribution.

(d) Obligatory contractual commitments.

(e) Generators

Article 225. Investment criteria for international connections

(1) The investment for international customers shall be in terms of the criteria set out for a dedicated connection, but the DC shall charge a connection charge that ensures that there is no cross border subsidies, as may be determined by the Commission or as stated in any of its guidelines or rules relating to tariffs.

Article 226. Excluded Services

(1) Excluded services may be acquired on competitive basis or provided by the DC as a monopoly service.

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

(3) Excluded services include the following:

(a) Design and construction of dedicated customer connections.

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

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

(4) For excluded services, customers will be allowed to choose a contractor other than the DC, provided that an agreement is reached between the DC and the customer prior to the project being undertaken detailing the conditions. These conditions will set out the following:

(a) The assets of the customer are allowed to work on or not.

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

(c) The terms and condition for the inspection and the work done prior to any agreement to take over and/or commission the supply.

(d) The charges to be raised by the DC for monopoly related services.

(5) The fees charged by the DC for excluded services may be regulated.

Section kk. Embedded Generators Connection Conditions

Article 227. Application for Connection to the Distribution Company

(1) Embedded Generators shall apply for connection to the Distribution System to the Distributor. A sample application form can be found in Appendix 7. Each DC shall develop and publish its own application form for connecting Embedded Generators based on the sample in Appendix 7.

Article 228. Responsibilities of Embedded Generators to DCs

(1) The Embedded Generator shall enter into a connection agreement with the DC before connecting to the Distribution System.

(2) The Embedded Generator shall ensure that the reliability and quality of supply complies with the terms of the connection agreement.

(3) The Embedded Generator shall comply with the DC's protection requirement guide, as well as, protection of own plant against abnormalities, which could arise on the Distribution System.

(4) The Embedded Generator shall be responsible for any dedicated connection costs incurred on the Transmission System or Distribution System as a result of connection of the Embedded Generation facility to the Distribution System and shall be clearly defined in the connection agreement between both the parties.

(5) The Embedded Generator shall be responsible for synchronizing the generating facility to the Distribution System within pre-agreed settings.

Article 229. Responsibilities of Distributors to the Embedded Generators

(1) If requested by the Embedded Generator, the DC shall provide information relating to the Distribution System capacity, fault levels and loading to enable the Embedded Generator to identify and evaluate opportunities for connecting to the Distribution System.

(2) The DC shall treat all applications for connection to the Distribution System by potential Embedded Generators in an open and transparent manner that ensures equal treatment for all applicants.

(3) The DC shall be responsible for the installation of the bidirectional metering equipment between the DC and the Embedded Generator's generation facility.

(4) The DC shall develop the protection requirement guide for connecting Embedded Generators to the Distribution System to ensure safe and reliable operation of the Distribution System

Article 230. Provision of Planning Information

(1) Before entering into a connection agreement, the Embedded Generator shall provide to the DC information relating to the Generator plant data, location and time scale, capacity and standby requirements as detailed in the Appendix 7.

(2) The DC shall provide the Embedded Generator any information necessary for the Embedded Generator to properly design the connection to the Distribution System.

(3) Embedded Generators shall specify, with all relevant details, in their application for connection if the generator facility to be connected shall have black-start and / or self-start capabilities.

Article 231. Connection Point Technical Requirements

(1) The Embedded Generator shall be responsible for the design, construction, maintenance and operation of the equipment on the generation side of the connection point.

(2) The Embedded Generator shall be responsible for the provision of the site required for the installation of the Distributor equipment required for connecting the generating facility.

(3) The technical specifications of the connection shall be agreed upon by the participants based on the Distribution System Impact Assessment Studies.

(4) A circuit breaker and visible isolation shall be installed at the connection point to provide the means of electrically isolating the Distribution System from the generating facility.

(5) The Embedded Generator shall be responsible for the circuit breaker to connect and disconnect the generator.

(6) The location of the circuit breaker and visible isolation shall be decided upon by the participants.

(7) The Embedded Generator shall pay for any expenses incurred by the DC on behalf of the Embedded Generator for the provision of Grid Connectivity.

Section II. Protection Requirement for Embedded Generators

Article 232. General Protection Requirements

(1) The Embedded Generator's protection shall comply with the requirements of this chapter. Embedded Generators of nominal capacity greater than 10 MVA shall in addition to the requirements of this chapter, comply with the Chapter IV of this Grid Code on connection to the Transmission Network.

(2) Additional features including inter-tripping and generator plant status to be agreed upon by the participants.

(3) The protection schemes used by the Embedded Generator shall incorporate adequate facilities for testing and maintenance.

(4) The protection scheme shall be submitted by the Embedded Generator for approval by the DC and / or the TNO.

Article 233. Specific Protection requirements

(1) Phase and Earth Fault Protection

(a) The protection system of the Embedded Generator shall fully coordinate with the protective relays of the Distribution System.

(b) The Embedded Generator shall be responsible for the installation and maintenance of all protection relays at the connection point.

(2) Over-voltage and over-frequency Protection

(a) The Embedded Generator shall install over-voltage and over-frequency protection to disconnect the generating facility under abnormal network conditions as agreed between the DC and the Embedded Generator.

(3) Faults on the Distribution System

(a) The Embedded Generator shall be responsible for protecting its generation facility in the event of faults and other disturbances arising on the Distribution System.

(4) Islanding

(a) The DC shall specify when the Embedded Generator may remain connected if the section of the Distribution System to which the Embedded Generator is connected is isolated from the rest of the network.

(b) The Embedded Generation facility shall be equipped with dead-line detection protection system to prevent the generator from being connected to a de-energised Distribution System. The DC shall take reasonable steps to prevent closing circuit breakers onto an islanded network.

(c) For unintentional network islanding, the Embedded Generator and the DC shall agree on methodology for disconnecting and connecting the Embedded Generator.

Article 234. Quality of Supply requirements

(1) Frequency Variations

The Embedded Generation facility shall remain synchronized to the Distribution System while the network frequency remains within the agreed frequency limitations as set out in this Grid Code.

(2) Power Factor

(a) The power factor at the connection point shall be maintained within the limits agreed upon by the Participants.

(3) Fault Levels

(a) The Embedded Generator shall ensure that the contractually agreed fault level contribution from the generation facility shall not be exceeded.

(b) The DC shall ensure that the contractually agreed fault level in the network at the point of connection shall not be exceeded.

Article 235. Embedded Generator Telemetry

(1) The Embedded Generator shall have the means to remotely report any status change of any critical function that may negatively impact on the quality of supply on the Distribution System.

Section mm. Power Station Supplies

Article 236. Power Station Supplies

(1) Every new power station supply excluding Embedded Generators will be a premium connection from a dedicated network.

(2) Every power station supply will be designed such that it will have the highest degree of reliability and availability, and would not be impacted by maintenance activities of participants other than the specific generator or embedded generator and the relevant distributor.

(3) The supply will be designed, constructed, maintained and operated in such a way, that it would be likely to remain available even if the local network (either distribution or transmission) into which the generator or embedded generator supply power, would fail.

Chapter XII. Distribution System Operation

Section nn. Objectives of Distribution System Operation

(1) To set out the responsibilities and roles of the participants as far as the operation of the Distribution System is concerned and more specifically issues related to:

(a) economic operation, reliability and security of the Distribution System

(b) operational authority, communication and contingency planning of the Distribution System

(c) management of power quality

(d) operation of the Distribution System under normal and abnormal conditions

(e) field operation, maintenance and maintenance coordination / outage planning

(f) safety of personnel and public

Article 237. Scope of Application of Distribution System Operation

(1) The chapter on Distribution System Operations shall apply to all Users of the Distribution System including:

(a) Distribution Companies (DC)

(b) Embedded Generators

(c) Generators

(d) End-use customers

(e) Traders / Retailers

(f) Any other entities with equipment connected to the Distribution System (such as transmission network operators (TNOs))

(g) System Operator (SO)

Section oo. Operational Responsibilities of DCs

Article 238. DC's Operational Responsibilities

(1) The DC shall operate the Distribution System to achieve the highest degree of reliability and shall promptly take appropriate remedial action to relieve any condition that may jeopardise reliability.

(2) The DC shall co-ordinate voltage control, demand control, operating on the Distribution System and security monitoring in order to ensure safe, reliable, and economic operation of the Distribution System.

(3) In the event of an embedded generator having to shut down or island plant because of a disturbance on the Distribution network, the DC shall carry out network restoration to minimise the time required to resynchronise the shed embedded generating units.

(4) Ensure that the availability and reliability of every power station supply is maximised at all times under normal and abnormal conditions

(5) The DC may shed customer load to maintain system integrity. Following such action, customer load shall be restored as soon as possible after restoring and maintaining system integrity.

(6) The DC shall operate the Distribution System as far as practical so that instability, uncontrolled separation or cascading outages do not occur.

(7) The DC is responsible for efficient restoration of the Distribution System after supply interruptions. The restoration plans shall be prioritised in accordance with DC's restoration schedule.

(8) The DC shall ensure it has sufficient resources to continuously monitor and operate the Distribution System.

(9) The DC shall establish and implement operating instructions, procedures, standards and guidelines to cover the operation of the Distribution System under normal and abnormal system conditions.

(10) The DC shall operate the Distribution System within defined technical standards and equipment operational ratings.

(11) The DC shall ensure adequate and reliable communications to all major users of the Distribution System. Communication with all customers shall be provided in terms of the licence requirement of the Commission.

Section pp. Operational Responsibilities of Embedded Generators and Other Customers on the Distribution Network

Article 239. Embedded Generators and Other Customers Operational Responsibilities

(1) When conditions on the Distribution System, under normal or abnormal conditions, become such that it may jeopardise plant or personnel of customers, customers shall immediately disconnect from the Distribution System.

(2) The Embedded Generator shall ensure that its generating units are operated within the capabilities defined in the Connection Agreement entered into with the DC.

(3) The Embedded Generator shall reasonably cooperate with the DC in executing all the operational activities during an emergency situation.

(4) Customers shall assist the DCs in correcting quality of supply problems caused by the Customer's equipment connected to the Distribution System.

(5) Customers shall at all times operate their equipment in such a manner to ensure that they comply with the conditions specified in their supply agreement.

(6) All customers must declare any generating plant (except for Embedded Generators) that may be paralleled with the Distribution network via switching, and specify the interlocking mechanism to prevent inadvertent parallel operation with the Distributor network.

(7) Embedded generators shall have the required protection to trip in the event of a momentary supply loss causing an island condition to prevent paralleling out of synchronism due to auto-reclose functionality on the DC's network.

Section qq. Operational Authority on the Distribution Network

Article 240. Operational Authority

(1) The DC shall have the authority to instruct operation on the Distribution System. Operational authority for other networks shall lie with the respective asset owners.

(2) Network control, as it affects the interface between the Distributor and a Customer, shall be in accordance with the operating agreements between the participants.

(3) Except where otherwise stated in this Grid Code, no participant shall be permitted to operate the equipment of another without the permission of such other participant. In such an event the asset owner shall have the right to test and authorise the relevant operating staff in accordance with its own standards before such permission is granted.

(4) Notwithstanding the provisions in Section oo of this Grid Code, participants shall retain the right to safeguard their own equipment.

Section rr. Operating Procedures for the Distribution Network

Article 241. Operating Procedures

(1) The DC shall develop and maintain operating procedures for the safe operation of the Distribution System, and for assets connected to the Distribution System. These operating procedures shall be adhered to by participants when operating equipment on the Distribution System or connected to the Distribution System.

(2) Each customer shall be responsible for his own safety rules and procedures at least in compliance with the relevant safety legislation. Customers shall ensure that these rules and procedures are compatible with the DC developed procedures defined in (1) above.

(3) Customers and service providers shall enter into operating agreements where not included in the supply agreement, as defined in the service provider licences.

Section ss. Operational Liaison amongst Distribution Network customers

Article 242. Operational Liaison

(1) The DC shall be responsible for ensuring adequate operational liaison with connected participants.

(2) The participants shall appoint competent personnel to operate their network and where needed shall establish direct communication channels amongst themselves to ensure the flow of operational information between the participants.

(3) If any participant experiences an emergency, the DC may call upon other participants to assist to an extent as may be necessary to ensure that such emergency does not jeopardise the integrity of the Distribution System.

(4) Pursuant to (3) above, the relevant participant shall ensure that the emergency notification contain sufficient details in describing the event including the cause, timing and recording of the event to assist the DC in assessing the risk and implications to the Distribution System and all the affected Customers' equipment.

(5) For planned events, which have an identified operational effect on the Distribution System, or on Customers' equipment connected to the Distribution System, the relevant participant shall notify the DC.

(6) Where it is possible for a Customer to parallel supply points or transfer load or embedded generation from one point of supply to another by performing switching operations on the customer's network, the operating agreement shall cover at least the operational communication, notice period requirements and switching procedures for such operations.

Section tt. Distribution Network Emergency and Contingency Planning

Article 243. Emergency and Contingency Planning

(1) The DC shall develop and maintain emergency and contingency plans to manage the system contingencies and emergencies that affect the delivery of the Distribution System and the Interconnected Power System. Such plans shall be developed in consultation with all affected participants, and shall be consistent with internationally acceptable practices, and shall include but not be limited to:

(a) under-frequency load shedding,

(b) prevention of voltage slide and collapse,

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

(d) forced outages at any point of connection,

(e) restoration and continuation of supply to every power station during normal and abnormal conditions is to be classified as a high priority,

(f) supply restoration.

(2) Emergency plans shall enable the safe and orderly recovery from a partial or complete system collapse, with minimum impact on customers.

(3) All contingency and emergency plans shall be reviewed biennially or in accordance with changes in network conditions.

(4) All contingency and emergency plans shall be verified by audits, if possible by using onsite inspections and actual tests. In the event of such tests causing undue risk or undue cost to a participant, the DC shall take such risks or costs into consideration when deciding whether to conduct the tests. Any tests shall be carried out at a time that is least disruptive to the participants. The costs of these tests shall be borne by the respective asset owners.

The DC shall ensure the co-ordination of the tests in consultation with all affected participants.

(5) The DC shall, in consultation with the TNO and SO, set the requirements and implement:

(a) Automatic or manual under-frequency load shedding in accordance with the System Operator's requirements.

(b) Automatic or manual under-voltage load shedding to prevent voltage collapse.

(c) Manual load shedding to maintain network integrity.

(6) Participants shall make available loads and schemes to comply with these requirements.

(7) The DC shall be responsible for determining emergency operational limits on the Distribution System, updating these periodically and making these available to the participants.

(8) The DC shall conduct network studies which may include but not be limited to load flow, fault level, stability and resonance studies to determine the effect that various component failures would have on the reliability of the Distribution System.

Section uu. Distribution Network Operation during Abnormal Conditions

Article 244. Operation during Abnormal Conditions

(1) During abnormal operating conditions the DC shall be obliged to take necessary precautionary measures to prevent network disturbances from spreading and to restore supply to consumers.

(2) The DC shall cooperate with the SO and TNO in taking corrective measures in the event of abnormal conditions on the Distribution System. The corrective measures shall include both supply-side and demand-side options. Where possible, warnings shall be issued by the DC to affected participants on expected utilisation of any contingency resources.

(3) The DC shall be entitled to disrupt some sections of the network in the event of a prolonged disturbance resulting from unsuccessful corrective measures undertaken.

(4) Termination of the use of emergency resources shall occur as the order of return being determined by the most critical loads, first in terms of safety and then plant.

(5) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with procedures prepared by the DC.

Section vv. Independent Actions by Participants in Times of Emergency within the Distribution Network

Article 245. Independent Actions by Participants in Times of Emergency

(1) Each participant shall have the right to reduce supply or demand, or disconnect a point of connection under emergency conditions, if such action is necessary for the protection of life or equipment and shall give advance notice of such action where possible.

Section ww. Distribution Network Demand and Voltage Control

Article 246. Demand and Voltage Control

(1) The DC shall implement demand control measures when:

(a) Instructed to, by the SO

(b) Abnormal conditions exist on the Distribution System,

(c) Multiple outage contingency exists resulting in island grid operation

(d) Any other operational event the DC believes warrants the implementation of demand control measures for the safe operation of the Distribution System.

(2) Demand control shall include but not limited to:

(a) Customer demand management

(b) Automatic under-frequency load shedding

(c) Automatic under-voltage load shedding

(d) Emergency manual load shedding

(e) Voluntary load curtailment

(3) The DC shall develop its procedures for load reduction, which shall be regularly updated, to reduce load in a controlled manner taking into consideration the type of load.

(4) The DC shall endeavour to maintain system voltage to be within statutory limits at the points of supply or otherwise as agreed in the operating / supply agreement.

Section xx. Distribution Network Fault Reporting and Analysis / Incident Investigation

Article 247. Fault Reporting and Analysis / Incident Investigation

(1) The large commercial and industrial end-use customers and Embedded Generators shall report the loss of major loads or generation (as agreed by the participants) to the DC within 15 minutes of the event occurring. A notice of intention to reconnect such shall be given at least 15 minutes in advance of the reconnection to enable the DC to take any necessary action required.

(2) The DC shall investigate all incidents that materially affected the quality of supply to another participant. The DC shall initiate and co-ordinate such an investigation and make available the findings of such investigation to affected participants and the Commission on request.

(3) The findings of such an investigation shall include where relevant:

(a) Date and time of the incident

(b) Location of the incident

(c) Duration of the incident

(d) Equipment involved

(e) Cause of the incident in compliance with the Power System Performance Standards in Chapter III of this Grid Code

(f) Demand control measures undertaken specifically recording the customer MWs shed and energy lost as a result of the measures taken.

(g) Supply restoration details.

(h) Embedded Generation interrupted

(i) Under-frequency Load Shedding response

(j) Estimated date and time of return to normal service

(k) Customer load tripped MW and energy lost when incident occurred or as a direct result of incident not including any Demand Control Measures taken

(l) Estimate number of customers having lost supply.

(m) Recommendations

(4) Any participant shall have a right to request an independent audit of the findings, at its own cost. If these audit findings disagree with the original findings, the participant may follow the dispute resolution mechanism as specified in Chapter XVII of this Grid Code.

Section yy. Distributor Maintenance Program

Article 248. Distributor Maintenance Program

(1) Each DC shall have a maintenance philosophy against which their maintenance practices and programs are compiled and documented, in format to be approved by the Commission. These documented maintenance programs must be auditable.

(2) The DC shall compile its maintenance and repair schedule for the following timeframes as required by Article 139 of this Grid Code:

(a) a 2 years ahead maintenance and repair plan

(b) a 12 months ahead maintenance and repair schedule

(c) a monthly maintenance and repair schedule

(d) a weekly maintenance and repair schedules

(e) a daily maintenance and repair schedule

(3) Accurate records of maintenance done shall be kept for a period of at least 5 years.

(4) Scheduling of planned outages should coincide with the maintenance requirements of other participants connected to the affected network as indicated in the SO's system outage plan.

(5) All participants that may be affected by the planned outages will be informed at least 2 days or 48 hours in advance.

Section zz. Distribution Network Testing and Monitoring

Article 249. Testing and Monitoring

(1) A participant has the right to request to test and / or monitor any equipment at the point of connection to the Distribution System to ensure that the participants are not operating outside the technical parameters specified in the provisions set out in this Grid Code relating to the Distribution System and other applicable standards which the participants are required to comply with. Such testing and / or monitoring shall be carried out as mutually agreed by the parties.

(2) A participant found to be operating outside the technical parameters shall, within such time agreed upon by the parties involved, remedy the situation or disconnect from its network the equipment causing problems.

(3) Any dispute arising out of the test and monitoring process shall be resolved through the dispute resolution mechanism specified in Chapter XVII of this Grid Code.

Section aaa. Distribution Network Safety Co-ordination

Article 250. Safety Co-ordination

(1) The DC shall comply with relevant legislation and develop Operating Procedures to ensure safety of personnel whilst operating on the Distribution System or any equipment connected to the Distribution System.

(2) Where operational boundaries exist, there shall be a joint agreement on operating procedures to be complied with by all affected participants.

(3) There shall be written authorisation of personnel who operate on or work on live equipment forming part of or connected to the Distribution System.

(4) The "Operating Procedures" referred to in (1) above of this Article shall include rules and regulations for the safe operating of plant, continuity of supply and authorisation of personnel related to the operating of HV, MV and LV equipment.

Section bbb. Disconnection and Reconnection of Distribution Network Customers

Article 251. Disconnection and Reconnection

(1) The DC may disconnect supply to the customer's supply address if the customer fails to comply with the written notice of non-compliance issued by the DC or any arrangement entered into by the DC and the customer which the customer has failed to comply with including non-compliance with the DC's applicable standards or with the relevant provisions of Article 11 of the Electricity Distribution and Supply (Consumer Service) Regulations 2019.

(2) The DC shall have the right to interrupt or disconnect supply if a threat of injury or material damage is anticipated as a result of the malfunctioning of the electrical installation equipment on the Customer's premises or on the Distribution System.

(3) The DC may disconnect immediately without notice the supply to the customer's supply address if:

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

(b) A customer takes at the customer's supply address electricity supplied to another customer.

(c) A customer is tampering with or permits tampering with the meter and associated components.

(d) A customer allows electricity supply to bypass the meter without the DC's consent.

(4) Customer (connected at MV and HV levels) shall give written notice to the DC of any intended voluntary disconnection.

(5) The DC shall reconnect supply to the customer on request by the customer subject to compliance with the applicable standards including the timing of reconnection and any reconnection charge imposed by the DC as set out in Article 13(2) of the Electricity Distribution and Supply (Consumer Service) Regulations 2019.

Section ccc. Commissioning and Connection of equipment or installations connected to the Distribution Network

Article 252. Commissioning and connection

(1) All programmes for commission of installations by MV and HV customers shall be supplied to the DC's at least 1 month in advance. Afterwards, at least 2 weeks before the actual connections, a notice of first connection shall be submitted to the DC. The information required for the commissioning of a connection shall include but not be limited to the following:

(a) Commissioning procedures and programmes

(b) Documents and drawings required

(c) Proof of compliance with standards

(d) Documentary proof of the completion of all required tests

(e) SCADA information, to be available and tested before commissioning where applicable.

(f) Site responsibilities and authorities.

(2) When equipment is been commissioned at the point of connection, the DC shall coordinate with the affected participants on all aspects that could potentially affect their operation.

(3) The DC and customers shall perform all commissioning tests required in order to confirm that the DC's and the customers' plant and equipment meet all the requirements set out in this Grid Code relating to connection to the Distribution System before being connected to and energised from the Distribution System.

Section ddd. Distribution Network Outage Scheduling and Co-ordination

Article 253. Responsibilities of the DC

(1) DCs shall, with reference to the relevant TNO's outage plans and relevant Generators outage programs, compile its daily outage schedule which shall:

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

(b) describe the planned outage

(c) identifies the risks and impact on network performance in accordance with Chapter VIII section (d) of this Grid Code

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

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

(2) Not withstanding (1) above, the DC shall co-ordinate relevant outages with the SO.

(3) The DC shall submit its daily outage schedule as prepared on to the SO.

(4) In addition to (1) above, the DC may require information from the Customers regarding major plant and associated equipment which may affect the performance of the Distribution System and may require additional resources to be committed during the outage planning process.

(5) Customers with co-generation and Embedded Generators with the maximum capacity greater than 1MW shall furnish to the DC information on planned outages

in order for the DC to properly plan, and coordinate its control, maintenance and operation activities.

(6) The Distribution outage schedule shall be submitted:

(a). To the Commission upon request.

(b). To the SO as required by Article 139 of this Grid Code.

Article 254. Risk-Related Outages

(1) All risk-related outages shall be scheduled with an executable contingency plan in place. The compilation of the contingency plan is the responsibility of the relevant DC.

(2) Contingency plans shall address:

(a) Safety of personnel

(b) Security and rating of equipment

(c) Continuity of supply

(3) The relevant control centres shall confirm that it is possible to execute the contingency plan successfully.

Article 255. Communication of System Conditions, Operational Information and Distribution System Performance

(1) The DC shall be responsible for making available to participants operational information as may be established from time to time. This shall include information relating to planned and forced outages on the DC.

(2) The DC shall notify participants of any network condition that is likely to impact the short and long-term operation of that participant.

(3) The DC shall record operational information according to Chapter XIII on Distribution Network Information Exchange. This information shall be provided to all participants on request.

Article 256. Unplanned Interruptions or Outages

(1) In case of unplanned interruptions or outages the DC may require a customer to comply with reasonable and appropriate instructions from the DC and may further:

(a) Require the customer to provide the DC emergency access to customer owned distribution equipment normally operated by the DC or DC owned equipment on customer's property.

(b) Interrupt supply to the customer to effect repairs to the Distribution System.

(2) Subsequent to (1) above the DC shall make arrangements to keep customers informed about the expected duration and other details following unplanned interruptions.

Article 257. Refusal / Cancellation of Outages

(1) No participant may unreasonably decline an outage request. No participant may unreasonably postpone or cancel a previously acknowledged outage.

(2) The direct costs associated with the retraction / deferment of an outage shall be borne by the corresponding asset owners.

Article 258. Planned Interruptions or Outages

(1) For planned interruptions or outages the DC shall act in accordance with the Electricity Distribution and Supply (Consumer Service) Regulations, 2019 and shall make available to the affected Customers information regarding the expected date of the outage, time and duration of the outage and shall established reasonable means of communication to the Customers for outage related enquiries.

Section eee. Distribution Network Telecontrol

Article 259. Telecontrol

(1) Where Telecontrol facilities are shared between the DC and other participants, the DC shall make certain that operating procedures are developed and implemented in consultation with the participants.

Chapter XIII. Distribution Network Information Exchange

Section fff. Objectives of Distribution Network Information Exchange

(1) To define the reciprocal obligations of participants with regard to the provision and exchange of planning, operational and maintenance information for the implementation of the provisions of this chapter on the Distribution Network.

(2) Information exchanged between participants governed by this Grid Code shall not be confidential, unless otherwise stated.

Article 260. Scope of Application of Distribution Network Information Exchange

(1) This section, Distribution Information Exchange, shall apply to the following participants:

(a) DCs

(b) Retailers / Traders

(c) Embedded Generators

(d) End-use customers

(2) Information requirements specified in the other sections on the Distribution Network / System are supplementary to this section. In the event of inconsistencies between other sections and this section on Distribution Information Exchange with respect to information exchange, the requirements of this section on Distribution Information Exchange shall take preference.

Section ggg. Distribution Network Information Exchange Interface

Article 261. Information Exchange Interface

(1) The parties shall identify the following for each type of information exchange:

(a) The name and contact details of the person(s) designated by the information owner to be responsible for provision of the information

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

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

(d) The parties shall agree on appropriate procedures for the transfer of information.

(2) Participants (with installed capacity of more than 100 kVA) shall exchange information, prior to commissioning, of new or altered equipment connected at the point of connection or changes to the operational regimes that could have an adverse effect on the Distribution System to enable proper modifications to any affected participants networks and related systems.

Section hhh. Provision and Exchange of Information during the Distribution Network Planning and Connection Process

Article 262. Information Exchange during the Planning and Connection Process

(1) Each DC shall have a supply application form, which shall request, at minimum, the information stipulated in this section.

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

(a) New or change in connected loads

(b) Type of load to be connected to the Distribution System

(c) Requested connection date

(d) Proposed network connection point address.

(3) Customers requesting supply at HV or MV shall, in addition to (2) above, provide the DC with the following information:

(a) Requested supply voltage

(b) Expected and / or projected maximum demand (in kVA)

(c) Expected load power factor

(d) Switched customer capacitor banks and reactors, which could affect the Distribution System

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

(f) The nature and type of process the supply is requested for

(g) Minimum required fault levels

(h) Start-up requirements

(i) Whether the customer has any standby generator.

(4) The DC may request Customers to provide information on the Customer's proposed installation and equipment at the Point of Connection.

(5) Participants shall exchange information relating to the protection of Distribution System and customer equipment protection coordination at the point of connection.

(6) Upon any reasonable request, the DC shall provide customers or potential customers with any relevant information that they require to properly plan and design their own networks / installations. This may include but not limited to:

(a) Nominal voltage at which connection will be made

(b) Method of connection, extension and/or reinforcement details

(c) The maximum and minimum fault levels

(d) Method of earthing

(e) Maximum installed Capacity at the point of connection

(f) Specification of any accommodation of equipment requirement

(g) Individual customer limits relating to:

i. Harmonic Distortion

ii. Voltage Flicker

iii. Voltage Unbalance

(h) Expected lead time of providing connection (following formal acceptance of terms for supply)

(i) An indication of network single contingency capability

(j) An indication of current network performance and power quality

(k) Cost of connection

(l) Range of current approved tariff structures

(7) Customers may be required to submit information as detailed in Appendix 9.

Section iii. Distribution Network Operational Information

Article 263. Commissioning and Notification

(1) Customers shall confirm that all information given in the application for supply and additional information subsequently requested by the DC is correct before the commissioning.

(2) The commissioning dates shall be negotiated between the parties. Participants will agree on the type of operational data to be submitted prior to commissioning, which shall include test and commissioning report.

(3) The asset owner (DC or Customer) shall ensure that all equipment records, that affect the integrity of the Distribution System or relevant to the interconnection, are maintained for reference for the duration of the operational life of the plant. On request from the DC, information shall be made available within a reasonable time.

(4) The DC shall indicate to the customer what information is relevant in terms of this section.

Article 264. Sharing Of Assets and Resources

(1) DCs sharing assets and resources shall enter into agreements for the provision and sharing of their assets, resources, services and information.

Article 265. Additional Information Requirements

(1) Should one participant, acting reasonably, determine that additional measurements and / or indications are needed in relation to another participant's plant and equipment; the requesting participant shall consult with the affected participant(s) to agree on the manner in which the need may be met. The costs related to the modifications for the additional measurements and/or indications shall be for the account of the causal participant.

Article 266. Communication and Liaison

(1) Participants shall establish a communication channel for exchange of information required for distribution operations, which may include the installation of DC's

SCADA equipment at the customer's or DC's installation to facilitate the flow of information and data to and from the DC and / or TNO's control facilities.

(2) Each participant shall designate a person with delegated authority to perform the duties of information owner in respect of the granting of access to information covered in this Grid Code to third parties. A party may, at its sole discretion, designate more than one person to perform these duties.

(3) The DC shall take reasonable steps to exchange information with the DC's affected customers for Distribution System and Transmission System outages.

(4) Customers shall exchange information with the DCs within an agreed lead time on all operations on their installations which may have an adverse effect on the Distribution System including any planned activities such as plant shutdown or scheduled maintenance.

(5) The communication facilities standards shall be set and documented by the DC. Any changes to communication facilities standards impacting on participant equipment shall be brought to the attention of the participant well in advance of the proposed upgrade.

(6) Any back up or emergency communication channels established by the DC and deemed necessary for the safe operation of the Distribution System shall be agreed upon by the DC and the participant affected.

Article 267. Data Storage and Archiving

(1) The obligation for data storage and archiving shall lie with the information owner.

(2) The systems that store the data and / or information to be used by the participants shall be of their own choice and for their own cost.

(3) All data storage systems must be able to be audited by the Commission. The systems must provide for clear and accessible audit trails on all relevant operational transactions. All requests that require an audit on a system shall be undertaken with reasonable notice to the parties.

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

(5) Participants shall ensure reasonable security against unauthorised access, use and loss of information for the systems that contain the information.

(6) DCs shall use a voice recorder for historical recording of all operational voice communication with participants. These records shall be available for at least three (3) months except where there is an incident involved, in which case the requirements of any applicable legislation shall apply. The DC shall make the voice records of an identified incident in dispute available within a reasonable time period after such a request from a participant and/or the Commission.

(7) An audit trail of all changes made to archived data should be maintained. This audit trail shall identify every change made, and the time and date of the change. The audit trail shall include both before and after values of all content and structure changes.

Section jjj. Confidentiality of Information by Distribution Network Users

Article 268. Confidentiality of Information Exchanged

(1) Information exchanged between participants connected to the distribution system shall not be confidential, unless otherwise stated.

(2) Participants receiving information shall use the information only for the purpose for which it was supplied.

(3) The information owner may request the receiver of information to enter into a confidentiality agreement before information, established to be confidential, is provided. A pro forma agreement is included in Appendix 8.

(4) Confidential information shall not be transferred to a third party without the written consent of the information owner. Parties shall observe the proprietary rights of third parties for the purposes of this Grid Code. Access to confidential information within the organisations of parties shall be provided as reasonably required.

(5) The participants shall take all reasonable measures to control unauthorised access to confidential information and to ensure secure information exchange. Parties shall report any leak of information that is governed by a confidentiality agreement as soon as practicable after they become aware of the leak, and shall provide the information

owner with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the information owner).

Chapter XIV. Distribution Metering

Section kkk. Objectives of Distribution Metering

(1) To ensure compliance with minimum requirements for tariff metering and energy trading metering installations.

(2) To define responsibilities for metering installations.

(3) To ensure that appropriate procedures are followed by the distributor of electricity (distribution licencee) and its metering service provider regarding the maintenance, validation, collection, processing and verification of metering data.

Article 269. Scope of Application of Distribution Metering

(1) This section on Distribution Metering shall apply to:

(a) Transmission Network Operators (TNOs)

(b) Distribution Companies (DCs)

(c) Embedded Generators

(d) Generators

(e) Traders / Retailers

(f) Resellers

(g) Metering service providers contracted by participants

(h) Other DCs connected to the TNO's or DC's System

(i) Other entities with equipment connected to the TNO's or DC's System

(2) The provisions for customers' rights and obligations in this section of the Code shall be referenced in the connection agreements with the licencee.

Section lll. Application of Distribution Metering and Its General Provisions

Article 270. Application of Distribution Metering

(1) This Grid Code is applicable to:

(a) metering installations used for the measurement of active and (where relevant) reactive energy and demand (where relevant)

(b) the design of the metering installation

(c) the provision, installation, commissioning and maintenance of metering equipment

(d) the minimum requirements of equipment used in the process of electricity metering

(e) testing procedures for metering installations

(f) the collection and verification of metering data

(g) storage requirements for metering data, and

(h) standards for the competencies of participants.

Article 271. General Provisions

(1) The Sierra Leone Standards Bureau (SLSB) shall from time to time publish the relevant standard for electricity metering which will specify the minimum requirements that metering installations and metering service providers shall adhere to. This section of the Code shall regulate compliance to the minimum set of requirements available for metering installations and metering service providers.

(2) The licencee shall only make use of metering equipment that has been certified by an accredited laboratory in terms of the relevant IEC / IEEE standards or the SLSB metering standards.

(3) Should there be a conflict in the interpretation between this section of the Code and any other national rationalized specification, this section of the Code shall take precedence.

Section mmm. Metering Requirements

Article 272. Installation Design Requirements

(1) The licencee shall ensure that the design of a metering installation complies with all requirements as specified in IEC 62053 and IEC 62058 or the relevant SLSB standard including the following:

a) The requirements for main and check or backup metering equipment;

b) The requirement for full four quadrant metering to be installed where active and reactive energy flow is in both directions.

c) The requirements for primary plant (Current and Voltage instruments transformers) where relevant.

d) The requirements for the meters specified to cater for the requirements of the applied tariff to the customer;

e) The requirements for metering data retrieval equipment to be catered for in the design based on the requirements of the licencee. For all TNO's metering installations equipment shall be installed to allow for remote interrogation of metering data.

f) Where AMR (automated meter reading) is utilised for large customers then the requirements of the relevant standards IEC 61107 and IEC 62056 shall be complied with.

(2) Metering equipment shall preferably be installed at the point of supply which defines the commercial boundary between the licencee and the customer. Where this is not possible, the metering point shall be located at the point agreed between the licencee and the customer.

Article 273. Metering Equipment Installation

(1) Where own metering staff or metering service providers (as defined in the Certification of Electricity Metering Service Providers Rules, 2019) are contracted for any work related to metering, the licencee remains accountable to ensure compliance with the requirements of Chapter X on metering and the technical requirements referenced therein. The DC (or licencee) shall thus only appoint own metering staff or metering service providers that have the necessary skills and authorization to install metering equipment. The skills requirements as specified in the Certification of Electricity Metering Service Providers Rules, 2019 shall be adhered to.

(2) Only equipment approved by the licencee shall be installed at a metering installation. The licencee shall maintain a list of approved equipment for metering installations.

(3) All primary and secondary equipment shall be calibrated and certified before installation as specified in Chapter X of this Grid Code.

(4) Commissioning of equipment shall be done following procedures that cater for the minimum testing requirements as specified in Chapter X of this Grid Code.

Article 274. Metering Equipment Maintenance

(1) The DC (or licencee) shall appoint own metering staff or metering service providers that have the necessary skills and authorization to maintain metering equipment.

The skills requirements as specified in the Certification of Electricity Metering Service Providers Rules, 2019 shall be adhered to.

(2) Metering installations shall be maintained according to the requirements and frequency specified in Chapter X of this Grid Code or any Metering Code as and when published by the Commission.

(3) For prepayment meters the inspection procedure shall be followed as stated in Electricity Quality of Supply Regulations, 2019.

Article 275. Metering Equipment Access

(1) Metering equipment owned by the licencee but installed on the customer's premises shall remain the property of the service provider.

(2) Customers shall not tamper or permit tampering with metering equipment owned by the licencee or any other service provider.

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

(4) Customers or customer representatives shall not have direct access to meters to obtain any metering information. Direct access includes access gained by downloading the metering information from the meter directly through the digital communication interface, or remotely through any communication media such as a PSTN or GSM modem, or any other means other than visual access. Requests from customers to read their own meters shall not be unreasonably refused.

(5) Except with written consent by the owner, customers or customer representatives shall not install any metering or other equipment integrated into the licencees CT and VT metering circuits, test blocks, terminals, or any portion forming part of the electrical metering installation.

(6) Customers shall provide reasonable access to the metering equipment owned and operated by the licencee but installed on the Customer's premises provided an official identification is produced on request.

(7) Where metering installation is situated in a restricted area, then a procedure (s) as stated in the Electricity Distribution and Supply (Consumer Service) Regulations, 2019, applicable legislation and / or as agreed between the parties shall be followed to gain access to the equipment.

(8) If a customer or his representative requires real time energy pulses (kWh & kVArh) at a metering installation, the licencee shall provide the real-time energy pulses through mutual agreement. The customer shall bear the costs of installation in such an event.

(9) Any changes that may affect the parties' authorised and safe access to the metering equipment shall be reported as soon as it is brought to either party's attention.

Article 276. Metering Data Access

(1) Official metering data shall be made available by the licencee on request by the customer in a format agreed upon between the parties.

(2) The licencee shall make available all formats at which it can provide data to the participant.

All new formats shall be negotiated between the licencee and the affected participant.

(3) The licencee shall store all metering data information in a central database for at least 5 years according to the requirements of Chapter X of this Grid Code. The licencee shall ensure that the database is maintained and continuously updated.

(4) Non-standard data provision format may be provided by the licencee, where possible, at the expense of the requesting party.

Article 277. Metering Data Retrieval

(1) The frequency of meter reading shall comply with the requirements specified in Chapter X of this Grid Code.

(2) Licencees shall ensure that the necessary data retrieval equipment and process are in place to achieve the meter read frequency as specified.

(3) The metering data retrieval process for automated meter reading (AMR) on large power user installations shall be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories. The retrieval process shall comply with the requirements in IEC 61107 and IEC 62056.

(4) Pre-payment metering installations are excluded from the requirements of this section.

Article 278. Data Validation and Verification

(1) The licencee shall carry out data validation and verification in accordance with Chapter X of this Grid Code.

(2) In the event of a substitution being made to metering data, the licencee or any other authorised person responsible for metering data validation or verification shall consult with the customer about the substitution and the basis upon which the substitution was made. No consultation is required for, where practised, the domestic account reconciliation process shall be done quarterly.

(3) The licencee shall maintain a journal of the substitutions made and shall provide access to the record when requested by the customer.

(4) Estimations shall be in accordance with Chapter X of this Grid Code.

Article 279. Metering Database

(1) The licencee shall create, maintain and administer a metering database containing all information as specified in Chapter X of this Grid Code.

(2) In the event of testing revealing that data in the metering database is inaccurate, the licencee shall inform all affected participants and corrections shall be made to the official metering data and the associated billing by mutual agreement.

Section nnn. Confidentiality of Metering Data

Article 280. Metering Data Confidentiality

(1) Metering data for use in energy trading and billing is confidential information and shall be treated in accordance with Chapter X of this Grid Code.

Section ooo. Customer Queries on Metering Integrity and Metering Data

Article 281. Customer Queries on Metering Integrity and Metering Data

(1) Where customers indicate they have a query or complaint related to metering, the licencee shall comply with the applicable requirements of Chapter X of this Grid Code.

(2) Any participant may request the licencee or metering service provider, to test a metering installation. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of the licencee unless the metering equipment is found to be within specification, in which event the cost shall be borne by the requesting participant.

(3) Alternatively, a customer may request an independent audit of metering installations done by approved metering service providers. The selection of the approved metering service provider shall be mutually agreed upon between the two parties. The requesting participant shall be responsible for any costs unless the metering installations are proved to be outside the defined standards.

(4) If errors are found with the metering after testing or auditing then the customer's account will be adjusted according to the rectified data.

(5) The audit result shall be submitted to the licencee and the licencee shall respond to the customer within 30 calendar days on any account or metering adjustments proposed in the audit report.

(6) Customers shall have the right to request an audit of the settlement process related to their account and the right to choose an independent third party qualified to perform the audit.

(7) Should no agreement be reached on account or metering disputes between the customer and the licencee the dispute resolution procedure shall be followed as stipulated by in Chapter XVII of this Grid Code.

THE INTEGRATION OF RENEWABLES SUB – CODE

Chapter XV. Integration of Renewable Energy into the Transmission and Distribution Networks

Article 282. Objectives of Variable Renewable Energy Integration into the Transmission and Distribution Networks

(1) The primary objective of this chapter on the integration of renewable energy into the Transmission and Distribution Network is to establish minimum technical and design grid connection requirements for Variable Renewable Power Plants (VRPPs) connected to or seeking connection to the electricity transmission and distribution networks in Sierra Leone.

Article 283. Scope

This chapter on the Integration of Renewable Energy into the Transmission and Distribution Network establishes the minimum technical performance and design grid connection requirements that a Variable Renewable Energy Power Plant (VRPP) needs to comply with in order to seek to connect its generation facility or to remain connected to the Transmission or Distribution Network in Sierra Leone.

(1). This chapter defines the rules and standards that the TNO shall follow when connecting VRPPs to its transmission network and the rules and standards that the DC shall follow when connecting a VRPP to its Distribution Network.

(2). Compliance with this chapter of the Grid Code is meant to ensure safe, reliable and secure operation of all transmission network connected VRPPs and all VRPPs connected to Distribution Networks.

(3). The basic technical performance requirements provided in this chapter applies to all VRPPs connected at voltage levels of 66 kV (transmission network) and above and to all VRPPs connected to voltage levels greater than 1 kV and up to 33 kV (distribution network).

(4). The TNO, DC and the VRPP operator shall supply each other with the necessary data and information about their network or plant that is required for ensuring compliance with this chapter of the Grid Code and if required, the DC shall facilitate the arrangement for a VRPP operator to contact the TNO for additional information.

In this chapter, VRPP technologies shall, at minimum, refer to the following:

a. Photovoltaic
b. Concentrated Solar Power
c. Small Hydro
d. Landfill gas
e. Biomass
f. Biogas
g. Wind

(4) Unless otherwise stated, the requirements in this chapter shall apply equally to all VRPP technologies.

(5) The VRPP shall, for duration of its generation licence issued by the Commission comply with the provisions of this Grid Code and all other applicable codes, rules and regulations approved by the Commission.

(6) Where there has been a replacement of or a major modification to an existing VRPP, the VRPP shall be required to demonstrate compliance to these requirements before being allowed to operate commercially.

(7) Compliance with this Grid Code shall be applicable to the VRPP depending on its rated power and, where indicated, the nominal voltage at the POC. Accordingly, VRPPs are grouped into the following categories:

(a) Category A: 1 MVA – 20 MVA

This category includes VRPPs with rated power in the range equal or greater than 1 MVA but less 20 MVA.

(c) Category B: 20 MVA or higher

This category includes VRPPs with rated power equal to or greater than 20 MVA.

(8) The requirements of this chapter are organized according to above defined categories. Unless otherwise stated, requirements in this chapter shall apply equally to all categories of VRPPs.

(9) Compliance with this and other codes requirements will depend on the interaction between the VRPP and the grid to which it is connected. The SO shall supply the VRPP

Generator with a reasonable detail of their TNO or DC that is sufficient to allow an accurate analysis of the interaction between the VRPP and the relevant parties in the SLEM, including other generation facilities.

Article 284. Definition of a VRPP

(1) A Variable Renewable Power Plant (VRPP) is a renewable energy power plant with continuously varying power output following the availability of primary energy without any storage (wind and solar PV farms).

(2) It is therefore the entire VRPP that shall be designed to achieve requirements of this Grid Code at the POC. A VRPP will generally have only one POC.

(3) In this Grid Code, the term VRPP is used as the umbrella term for a unit or a system of generating units producing electricity based on a primary renewable energy source (e.g. wind, sun, water, biomass etc.). A VRPP can use different kinds of primary energy source.

(4) A RPP that consists of a homogeneous type of generating units can be named as follows:

a) PV Power Plant (PVPP) – A single photovoltaic panel or a group of several photovoltaic panels with associated equipment operating as a power plant.
b) Concentrated Solar Power Plant (CSPP) – A group of aggregates to concentrate the solar radiation and convert the concentrated power to drive a turbine or a group of several turbines with associated equipment operating as a power plant.
c) Small Hydro Power Plant (SHPP) – A single hydraulic driven turbine or a group of several hydraulic driven turbines with associated equipment operating as a power plant.
d) Landfill Gas Power Plant (LGPP) – A single turbine or a group of several turbines driven by landfill gas with associated equipment operating as a power plant.
e) Biomass Power Plant (BMPP) – A single turbine or a group of several turbines driven by biomass as fuel with associated equipment operating as a power plant.
f) Biogas Power Plant (BGPP) – A single turbine or a group of several turbines driven by biogas as fuel with associated equipment operating as a power plant.
g) Wind Power Plant (WPP) – A single turbine or a group of several turbines driven by wind as fuel with associated equipment operating as a power plant. This is also referred to as a wind energy facility (WEF)

Section ppp. Technical Connection Conditions for VRPPs

Article 285. General

(1). The interconnection of a VRPP to a TNO's network shall not deteriorate system security; in the same way, the interconnection of a VRPP into a distribution network shall not deteriorate the system security.

(2). A VRPP shall meet the requirements of this Grid Code at the POC to a TNO's network or a DC's network unless otherwise agreed upon by the TNO or the DC.

(3). The design, installation, commissioning, maintenance and operation of the generation facility shall be conducted in a manner that ensures safety and security of both VRPP and TNO's network where connected to a transmission network or to a DC's network when connected to a distribution network.

(4). A VRPP operator shall maintain and operate power plants in accordance with the instructions of the TNO and DC to supply electricity through the transmission network to consumers and through the distribution network to consumers respectively.

(5). The parties herein involved:

a. TNO or DC shall not assume any responsibility for the protection of a Grid Participant's plant or equipment or any other portion of the Grid Participant's electrical equipment. A Grid Participant shall be responsible for protecting its equipment in such a manner that faults or other disturbances in the transmission or distribution network does not cause damage to the Grid Participant's equipment.

b. A VRPP or any other generator or consumer connected to the distribution network shall be responsible for protecting its equipment in such a manner that faults or other disturbances in the transmission network or distribution network do not cause damage to their equipment.

(6). A VRPP shall at all times comply with applicable requirements and conditions of connection for generating units and in accordance with any Connection Agreement with the TNO or with the DC.

(7). A VRPP operator shall permit and arrange the participation of the TNO or the DC in the inspection, testing or commissioning of facilities and equipment to be connected to the transmission network or distribution network.

(8). At the request of the TNO or DC, a VRPP operator shall conduct equipment parameter tests to certify specification of power plant from time to time.

Article 286. Operational Frequency Range / Tolerance of Frequency and Voltage Deviations

(1) The VRPP shall be able to withstand frequency and voltage deviations at the POC under normal and abnormal operating conditions described in this Grid Code while reducing the active power as little as possible.

(2) The VRPP shall be able to support network frequency and voltage stability in line with the requirements of this grid code.

(3) Normal operating conditions and abnormal operating conditions are described in Chapter III of this Grid Code.

Article 287. Frequency Range of Operation

(1). A VRPP shall be capable of staying connected to the TNO's transmission network or a DC's distribution network within the frequency ranges and times specified in Table 11.

Table 11: Frequency Ranges of Operation (Must remain connected conditions

Frequency (Hz)	**Operation**
$47 \leq f < 47.5$	15 minutes
$47.5 \leq f < 48.75$	90 minutes
$48.75 \leq f < 49.5$	180 minutes
$49.5 \leq f < 50.5$	Unlimited (continuous range)
$50.5 \leq f < 51.25$	180 minutes
$51.25 < f \leq 51.5$	90 minutes
$51.5 < f \leq 52$	15 minutes

(2). In case of frequencies outside the frequency and time ranges specified in Table 11, a VRPP shall be allowed to disconnect from the TNO's transmission network or the DC's distribution network, as the case may be.

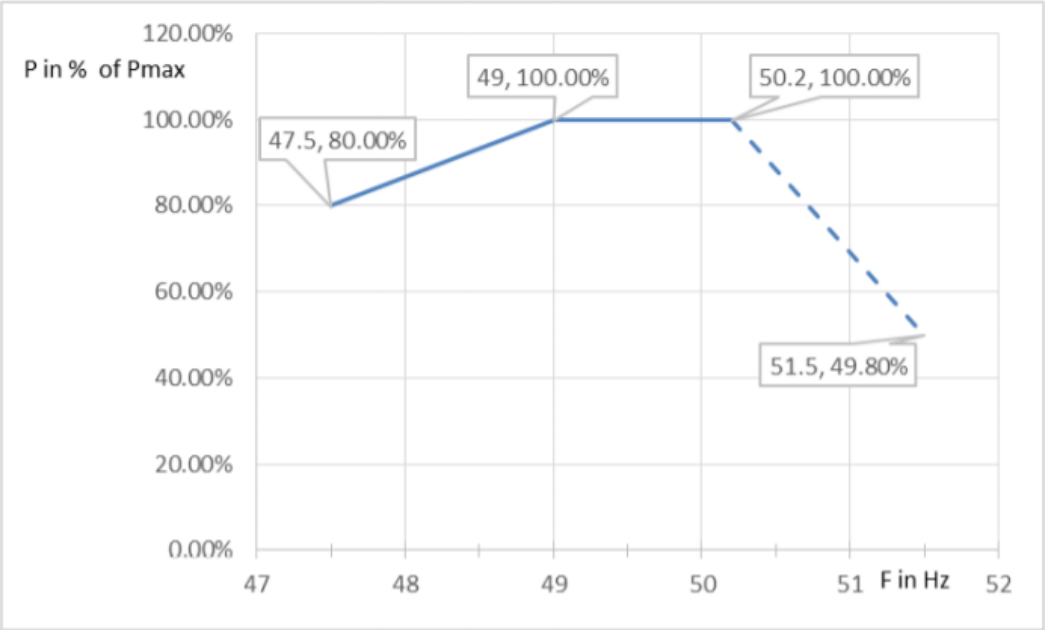


Figure 1: Maximum Active Power Capability in Function of Frequency

(3). There shall be no technical restriction with regard to the delivery of active power or reactive power within the frequency range of 49 Hz to 51 Hz and a VRPP shall be permitted unrestricted operation within this frequency range.

(4). The minimum active power output that a VRPP shall be capable of delivering is depicted in Figure 1.

Note 1: The frequency dependent power limits according to Figure 1 relate to the technical capability under the condition that sufficient primary energy is available (e.g. wind speed, solar irradiation). Additional limits due to limited primary energy may apply but these limits are not frequency dependent.

Note 2: The dashed line displayed for frequencies >50.2 Hz results from the high frequency response according to Article 19 (1) and doesn't represent a technical restriction.

Article 288. Operational Voltage Range

(1). For a VRPP, no disconnection of any unit within a power park is permitted as long as voltage at POC remains within ±10% of nominal voltage or within IEC-voltage limits for continuous operation, whichever is the narrower voltage range (Continuous Voltage Range).

(2). For voltages at the POC between ±5% of nominal voltage, no restrictions with regard to the provision of active or reactive power are permitted (Unrestricted Voltage Range).

Article 289. Power Quality

(1). A VRPP shall ensure that the power it injects into the TNO's transmission network or a DC's distribution network is within the limits prescribed in this sub-section.

(2). A VRPP operator shall continuously monitor the power quality and submit periodic report

(3). All power quality parameters shall be monitored at POC and shall comply with limits presented in this chapter of this Grid Code.

Note: For the purpose of VRPPs, power quality parameters refer to voltage, flicker and harmonics.

Article 290. Rapid Voltage Changes

(1). During regular switching operations within a VRPP such as switching operation on a wind turbine within a wind farm or switching of a shunt reactor/capacitor, the resulting voltage change at POC shall not deviate more than 2% of the Nominal Voltage.

(2). The maximum permitted voltage change at any point in the network shall be limited to 5 % of Nominal Voltage in respect of changes resulting from

a. switching of several units within a VRPP,

b. connection of a complete VRPP, or

c. disconnection of a complete VRPP.

Article 291. Flicker

(1). A TNO or DC, as the case may be, shall apportion flicker emission limits to each VRPP based on flicker planning levels according to Article 27 and Article 41 of this Grid Code (P_{lt} =0.6 , P_{st}=0.8) or IEC61000-3-7, existing background flicker levels, possible future installations and the total size of a VRPP to be connected. The methodology for apportioning VRPP-specific flicker limits shall be in-line with IEC61000-3-7.

(2). In the absence of any flicker limits apportioned by the TNO or DC, flicker caused by a VRPP shall not exceed the limits depicted in Table 12 at the POC.

Table 12: Flicker limits to be applied in the absence of apportioned limits

Parameter	Emission Limit (HV-EHV)	Emission Limit (MV)
P_{st}	0.3	0.4
P_{lt}	0.3	0.4

Article 292. Voltage Unbalance

(1). A VRPP shall not cause phase voltage unbalance exceeding 1 % in unrestricted operation range and 2 % when in continuous operation range. A VRPP shall also be capable of withstanding the same in the transmission network.

Note: Voltage unbalance is measured in terms of negative sequence voltage in per cent of nominal voltage.

Article 293. Harmonics

(1). TNO shall apportion individual harmonic distortion limits to each VRPP, via the Commission, based on a planning level for THD according to Article 26 and Article 40 of this Grid Code, existing background disturbances, possible future installations and the total size of a VRPP to be connected, according to methodology described in IEEE Std. 519-1992 for transmission networks and in IEC 61000-3 for distribution networks.

(2). Generally, individual harmonic voltage distortion limits for odd harmonics shall not exceed 2 % and for even harmonics 1 %. Total harmonic voltage distortion shall not exceed 3% at the POC. Notwithstanding, in the absence of any apportioned limits, harmonic voltage distortion limits at POC according to Table 13, shall apply.

Table 13: Harmonic Voltage Distortion limit for generators connected to the transmission network

Voltage at POC (kV)	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
$33 < V \leq 66$	3.0	5.0
$66 < V \leq 161$	1.5	2.5
$161 < V$	1	1.5

(3). In addition to (2), generators shall not exceed harmonic current distortion limits specified in Table 14 at the POC.

Table 14: Current Harmonic Distortion limits

I_{SC}/I_L	**Maximum Harmonic Current Distortion in percent (%) of I_L**					
	Individual Harmonic Order "h" (Odd Harmonics)					
	<11	**11<h<17**	**17<h<23**	**23<h<35**	**35<h**	**TDD**
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

* All power generation equipment are limited to these values of current distortion, regardless of actual I_{sc}/I_L.

1. Even harmonics are limited to 25% of the odd harmonic limits above.
2. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
3. I_{sc} = maximum short-circuit current at POC.
4. I_L = maximum demand load current (fundamental frequency component of generation current) at POC.
5. TDD (Total Demand Distortion) = harmonic current distortion in % of maximum demand load (or generation) current (15 or 30 min demand).

Article 294. Reactive Power Capability

(1). A VRPP shall operate within a power factor within the range of 0.90 leading to 0.90 lagging, measured at the POC.

(2). For voltages between 0.9 and 1.0 p.u., a VRPP shall provide maximum reactive support to the system or for voltages between 1.0 and 1.1p.u., a VRPP shall provide full bucking at the POC.

(3). A VRPP shall be capable of varying power factor continuously in the entire range of 0.90 under-excited to 0.88 over-excited during operation with maximum active power output and voltage within the Unrestricted Range of Operation.

(4). A VRPP shall be capable of varying reactive power at the POC within their reactive power capability range as defined by Figure 3 when connected to the transmission network and as defined in Figure 5 when connected to the distribution network, when operating within the Unrestricted Voltage Range and at an active power output level between 5% and 100% of Rated Power.

(5). If voltage is outside the Unrestricted Voltage Range but within the Continuous Voltage Range the reactive power capability limits of a VRPP according to Figure 3 (when connected to the transmission network) and according to Figure 5 (when connected to the distribution network) can be adjusted to the voltage dependent limits according to Figure 2 (for a connection to the transmission network) and according to Figure 4 (for a connection to the distribution network).

Note: P_n in MW corresponds to the rated installed capacity of a VRPP minus the sum of the installed capacity of all units being temporarily out of service (e.g. on maintenance).

(6). In the case of operation with active power below 5% of P_n, there is no reactive power capability requirement but in this range, reactive power must be within the tolerance range of +/-5% of P_n.

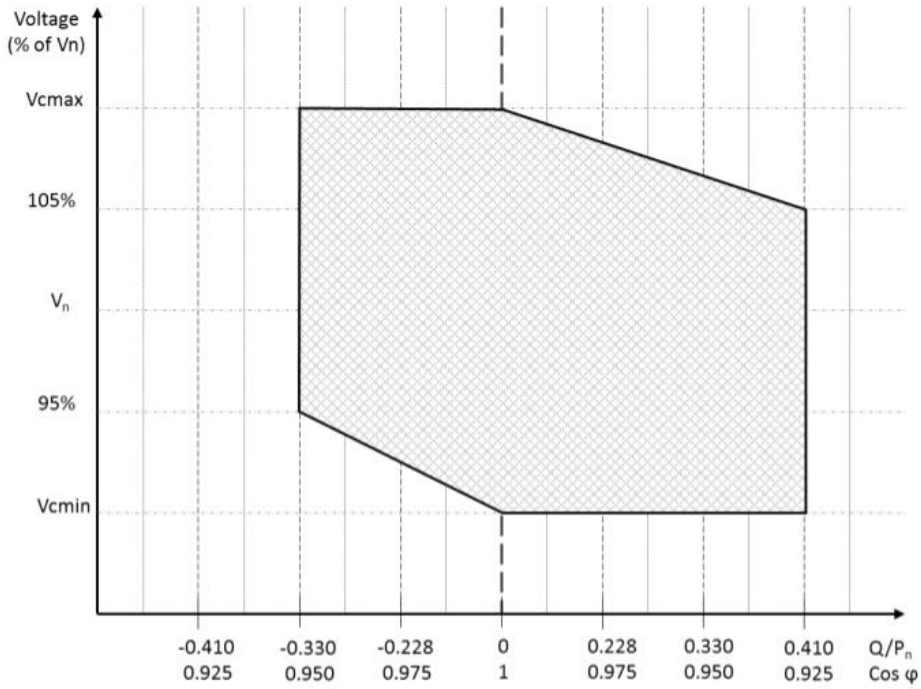


Figure 2: Reactive power requirements for transmission network connected VRPPs (corresponding to voltage)

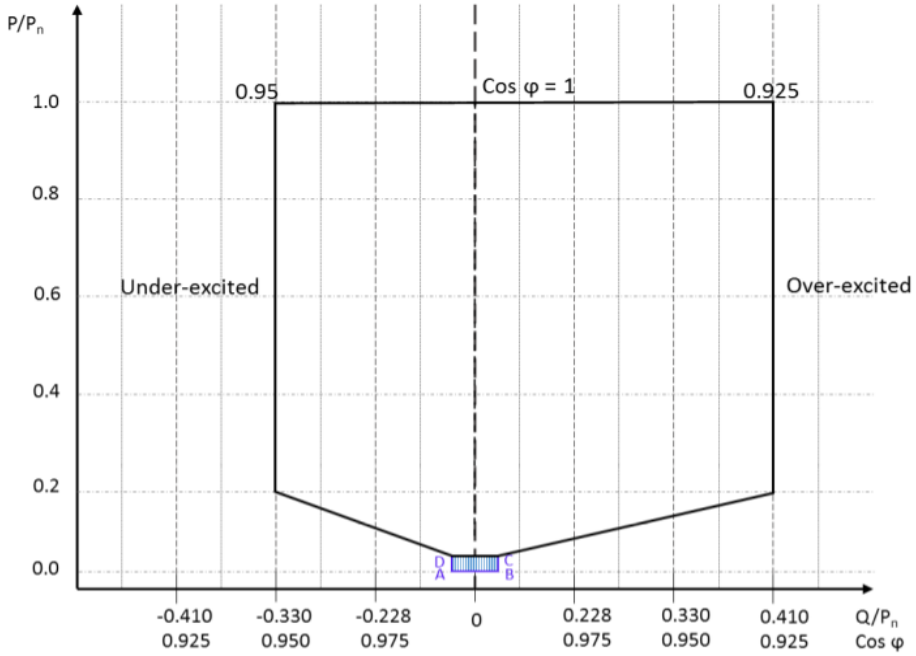


Figure 3: Reactive power requirements for transmission network connected VRPPs at full/partial active power output conditions

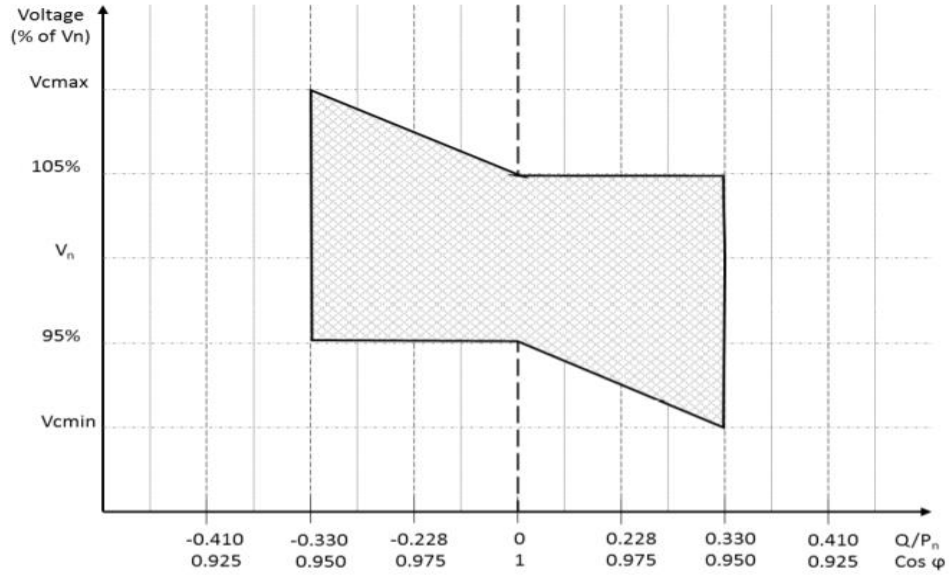


Figure 4: Reactive power requirements for distribution network connected VRPPs (corresponding in voltages)

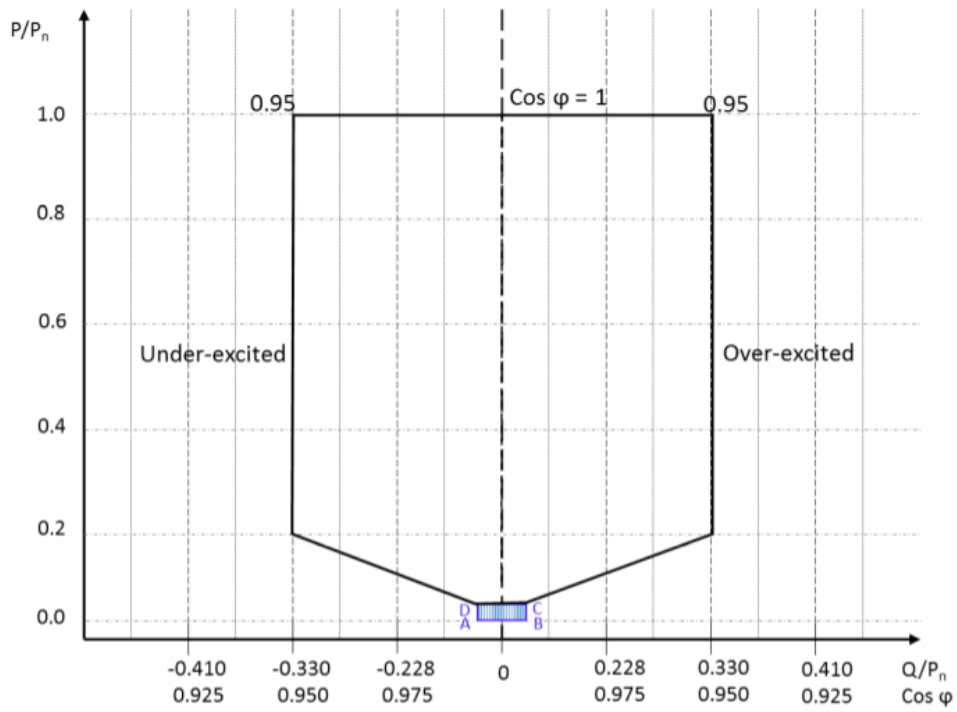


Figure 5: Reactive power requirements for distribution network connected VRPPs at full and partial active power output conditions

Article 295. Reactive Power Control Requirements - General

(1). A VRPP shall be equipped with control functions to control reactive power or voltage at the POC via orders from either the TNO or DC, as the case may be, using set-points and gradients. The parameter settings shall be agreed between the VRPP operator and the TNO or the DC, as the case may be, or shall be as documented in the relevant System Operational Manual.

(2). A VRPP shall support each of the following control functions:

a. Voltage control (to the TNO)

b. Q control (to the TNO or DC)

c. Power Factor Control (to the TNO or DC)

(3). The choice of control mode and the definition of target values shall be within the responsibility of the TNO or the DC, as applicable, and it must be possible for the TNO or DC to change control mode and target values at any time during the lifetime of a VRPP, in coordination with the VRPP.

Article 296. Reactive Power – Voltage Control

(1). A VRPP shall be equipped with a voltage control function that is capable of controlling voltage at the POC according to a voltage target specified by the TNO and according to a droop-characteristic, as defined in Figure 6.

(2). In the case that the TNO choses a “droop” characteristic, the “droop” shall be specified by the maximum voltage change in p.u. at maximum reactive power output (Q_{max}).

(3). If the voltage control target is changed by TNO, such change shall be completed no later than 2 minutes after the receipt of the new set-point value.

(4). The maximum permitted deviation of the actual voltage from the target voltage shall be no greater than 0.5% of nominal voltage, that is 0.005 p.u., 2 minutes after change of voltage-target, during steady system conditions.

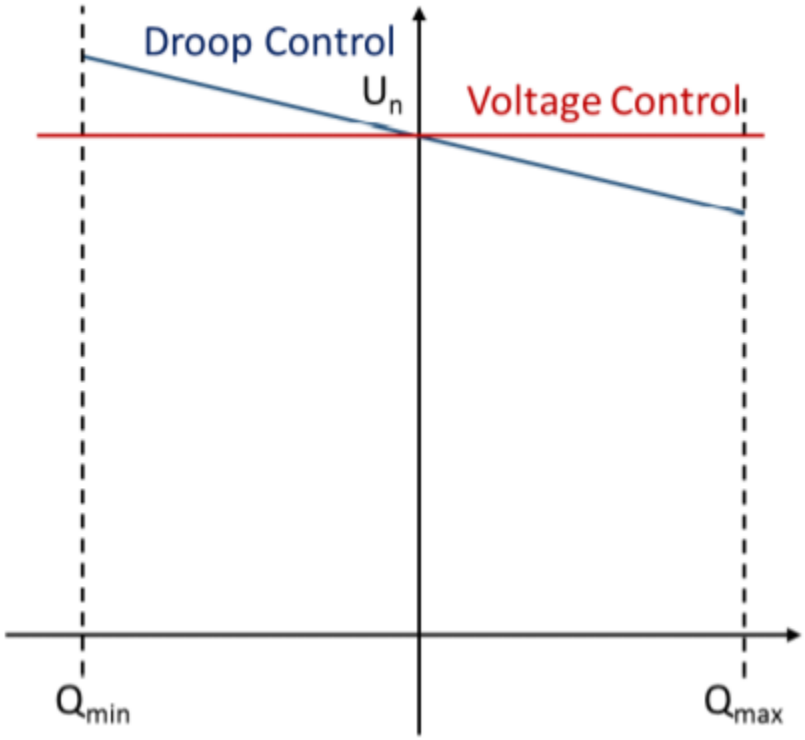


Figure 6: Voltage control function of transmission network connected VRPP

Article 297. Reactive Power Control (Q Control)

(1). A VRPP shall be capable of controlling reactive power at the POC either to a constant reactive power target (Q-target) or an active power dependent reactive power target (Q(P)).

(2). The TNO or DC, as applicable, shall define the actual settings of the Q/Q(P) control characteristic (shape of Q(P)-characteristic, target values).

(3). If the control target is changed by TNO or DC, such change shall be completed not later than 2 minutes after the receipt of the new target value.

(4). The maximum permitted deviation of actual reactive power from the Q-target shall be no greater than 2% of rated power, that is 0.02 p.u., 2 minutes after change of Q-target during steady system conditions.

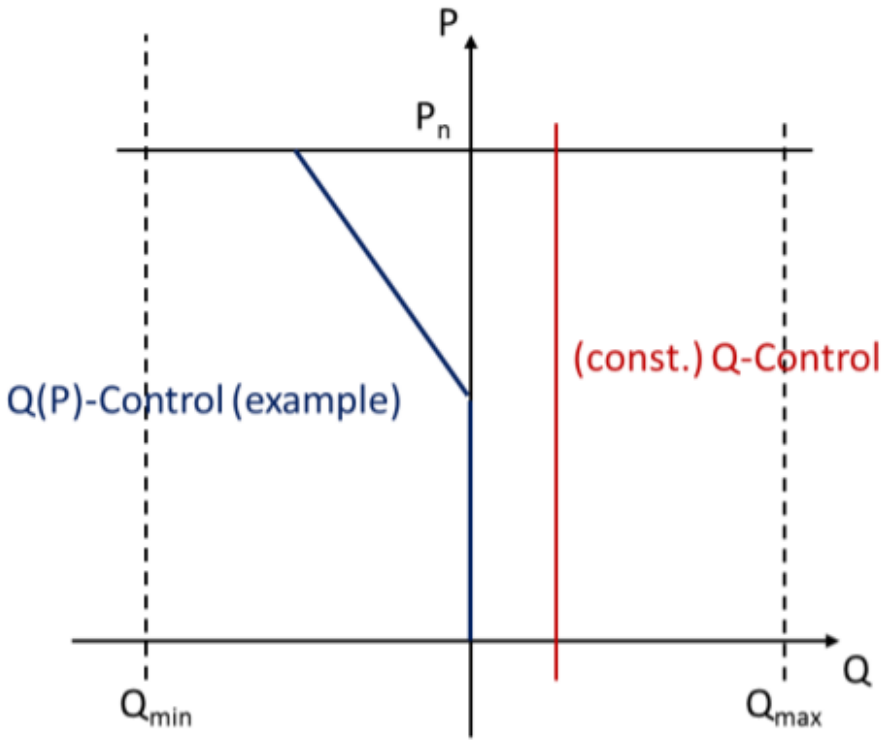


Figure 7: Reactive power control function of transmission network connected VRPP (constant Q-control and Q(P)-control)

Article 298. Power Factor Control (Cos φ-Control)

(1). A VRPP shall be capable of controlling power factor at the POC either to a constant power factor target (cosφ target) or an active power dependent power factor target (cosφ(P)).

(2). The TNO or DC, as applicable, shall define the actual settings of the cos φ/cos φ(P) control characteristic (shape of cos φ(P) – characteristic, cos φ-target).

(3). If the control target is changed by TNO or DC, as applicable, such change shall be completed no later than 2 minutes after the receipt of the new target value.

(4). The maximum permitted deviation of actual power factor from the cosφ-target shall be no greater than $\Delta cos\ \varphi = 0.005$, (that is 2 minutes after change of cosφ-target during steady system conditions).

Article 299. Active Power Control

(1). For system security reasons it may be necessary for the TNO or DC to curtail a VRPP active power output.

(2). A VRPP shall be capable of operating at a reduced power level if active power has been curtailed by TNO or DC, for network or system security reasons;

(3). The accuracy of the control performed and of the set-point shall not deviate by more than ±1 % of the rated power.

(4). The type of communication between TNO or DC, as applicable, and VRPP operator must be agreed between the parties and specified as part of the bilateral connection agreement between the parties.

(5). The relationship between the TNO and a VRPP shall be specified as part of the bilateral connection agreement between the DC and a VRPP.

Section qqq. Frequency Response

Article 300. High Frequency Response for VRPPs

(1). During high frequency operating conditions on the transmission network or on the distribution network, each VRPP, whether connected to the transmission network or to the distribution network, as the case may be, shall be required to operate at reduced active power output in order to stabilize grid frequency.

(2). When the frequency on the transmission network and the distribution network exceeds 50.2 Hz, each VRPP shall be required to reduce active power as a function of change in frequency as illustrated in Figure 8.

(3). High frequency response must operate with a minimum ramp rate of 100% of rated power per minute as provided by the primary frequency control time scales.

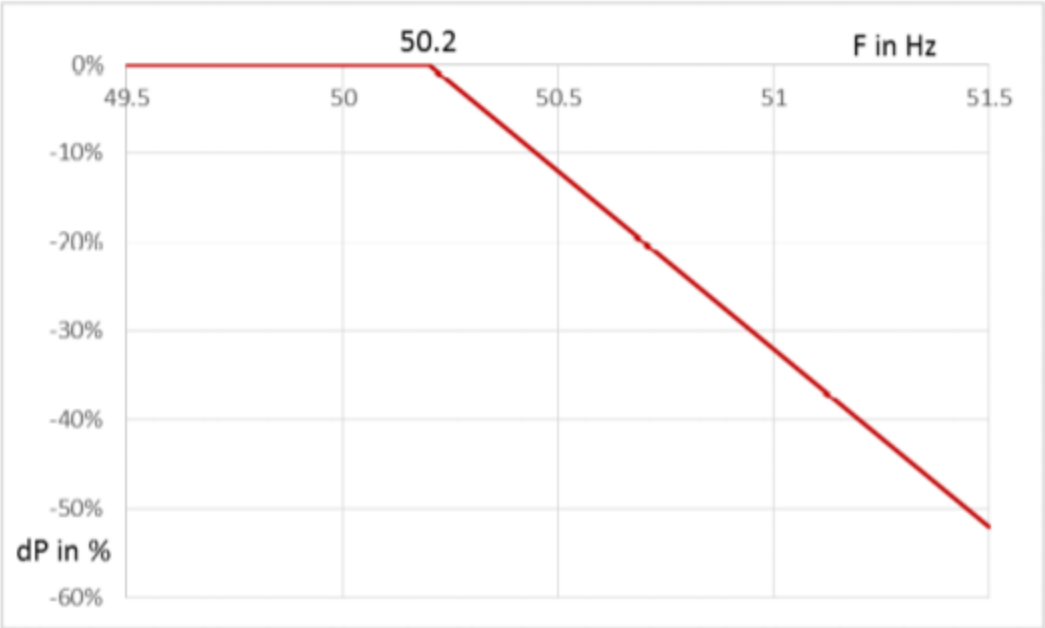


Figure 6: Mandatory high frequency response for all NITS connected VRPPs

Figure 8: Mandatory high frequency response for all VRPPs

Note: 'dP' in the figure represents percentage of active power by which the output has to be decreased in case of increasing system frequency.

Article 301. Primary and Secondary Frequency Control

(1). Unless otherwise required by the TNO or DC, a VRPP is exempted from primary or secondary frequency control capabilities except from high frequency response as stated above.

Section rrr. Behaviour during Abnormal Voltage Conditions

Article 302. Low Voltage Ride Through (LVRT)/High Voltage Ride Through (HVRT) Capability for VRPPs

(1). A VRPP shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

(2). A VRPP shall be designed to operate for up to one minute within a voltage range of +/-15% of nominal voltage.

(3). A VRPP shall be designed to have LVRT and HVRT capability as illustrated in Figure 9 (for transmission network connected VRPPs) and Figure 10 (for distribution network connected VRPPs).

(4). For all voltages at the POC, which are between HVRT and LVRT according to Figure 9, (for transmission network connected VRPPs) and Figure 10 (for distribution network connected VRPPs), no disconnection of a VRPP or of individual units within a VRPP is permitted.

(5). The voltage at POC is defined to be the lowest of the three line-line or line-earth voltages.

(6). If the voltage reverts to the Continuous Voltage Range (between Vc_{min} and Vc_{max}) during a fault sequence (e.g. resulting from reclosing), subsequent voltage drops or voltage spikes shall be regarded as new LVRT or HVRT condition.

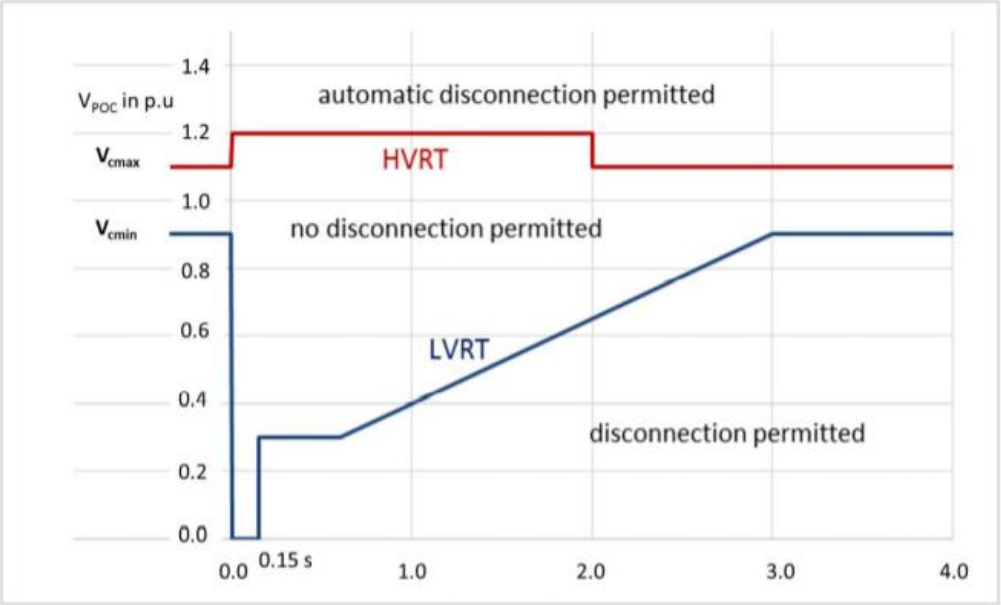


Figure 9: LVRT and HVRT capability for transmission network connected VRPPs

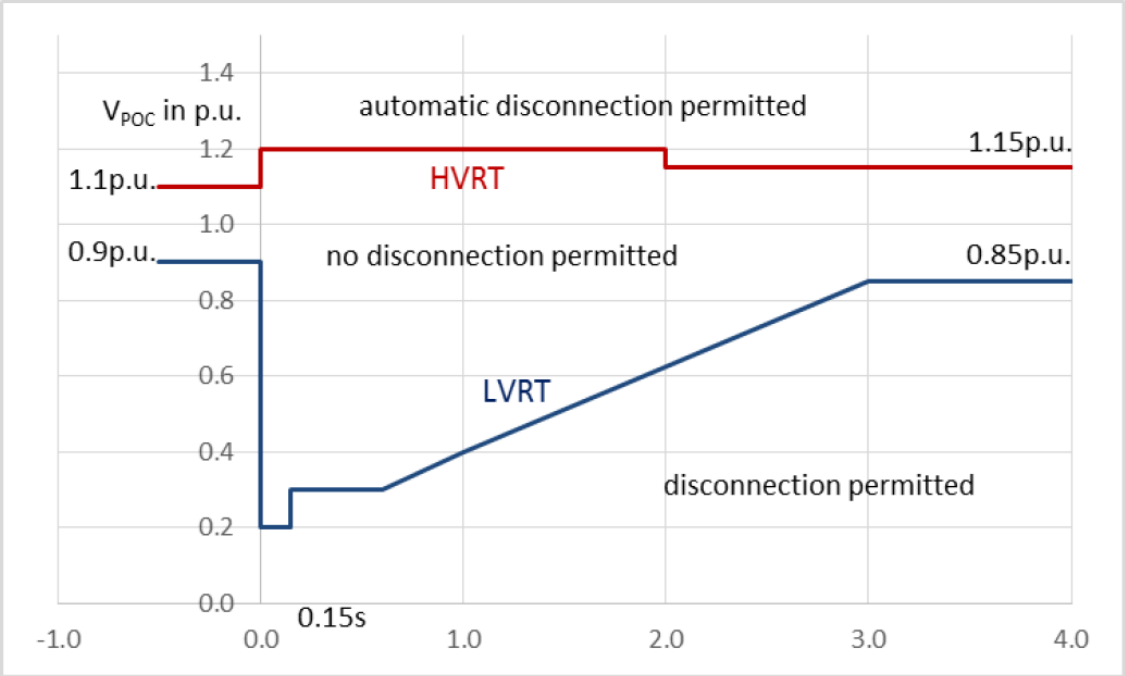


Figure 10: LVRT and HVRT capability for distribution network connected VRPPs

Article 303. Reactive Current Support During LVRT/HVRT Situations

During LVRT and HVRT situations, both symmetrical and asymmetrical, any VRPP having a direct connection to the secondary side of a substation shall support the DC's network voltage by injecting (or absorbing) reactive current as follows:

(1). All units within a VRPP shall support the voltage by injecting or absorbing additional reactive current ΔI_q at the generator terminals proportional to the change of the unit's terminal voltage ΔV_t, as depicted in Figure 11.

(2). The factor of proportionality between additional reactive current and voltage deviation is named K ($\Delta Iq = K\Delta Vt$) and the factor K must be settable in the range of $0 \leq K \leq 10$.

(3). The absolute value I of current in each of the three phases of the unit's terminals may be limited to rated current (1 p.u.).

Notes:

1. Voltages and currents in this section are defined to be positive sequence components of fundamental frequency value of voltages and currents respectively. This applies to pre-fault and post-fault voltages and currents.

2. The additional reactive current ΔI_q shall be injected in addition to the pre-fault voltage.

3. The positive sign of ΔI_q in Figure 11 is voltage supporting injection of reactive power.

4. The voltage deviation ΔV_t is defined by the difference between the pre-fault and the post-fault voltage.

5. The pre-fault current and pre-fault voltage are defined by the 1-minute average of current and voltage respectively.

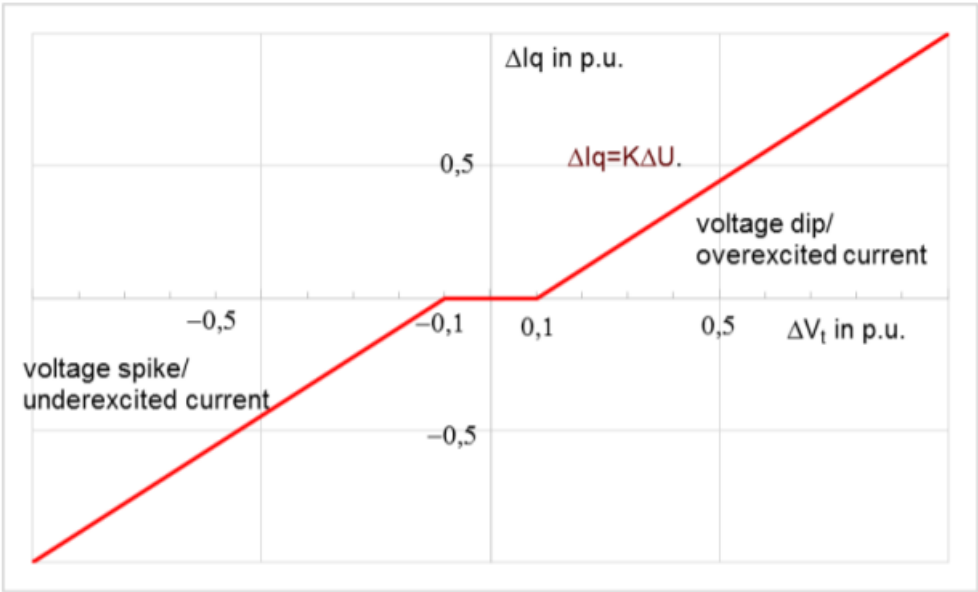


Figure 11: Reactive current support ΔIq during LVRT and HVRT situations at the unit's terminals

(4). During dynamic performance, after 60ms the additional current must have settled, meaning that it shall remain within a tolerance band of ±20% around the value according to Figure 11.

(5). For the transmission network, during LVRT and HVRT conditions, the active current I_P shall be reduced in proportion to the voltage change ΔVt.

(5). For the distribution network:

a. During a LVRT situation, a VRPP having a connection on a distribution feeder shall control active and reactive power according to a "zero current" strategy, meaning that both, active and reactive current shall be reduced to zero.

b. During a HVRT situation, a VRPP having a connection on a distribution feeder shall maintain normal active and reactive power control modes.

Article 304. Active and Reactive Power Behaviour During Voltage Recovery

(1). After voltage at POC has returned into the Continuous Voltage Range (+/-15% of nominal voltage), a VRPP shall restore its active power output to at least 90% of its pre-fault value within 1 second.

(2). During voltage recovery, a VRPP shall not absorb more reactive power than prior to the LVRT situation.

Article 305. Automatic Re-synchronisation

(1). Automatic synchronization device and automatic close equipment shall be installed to allow a VRPP to connect to the TNO or DC, as applicable, automatically, with a delay of 5 minutes if the following system conditions are fulfilled:

a. for a transmission network, TNO is in a Normal State, as defined in the relevant sections of this Grid Code.

b. for a distribution network:

i. the voltage at the POC is within the Steady State Range of +/-10% of nominal voltage, as specified in the relevant sections of this Grid Code.

ii. Frequency is within the range of 49.8 Hz ≤ f ≤ 50.2 Hz.

(2). During automatic connection or synchronisation, a VRPP must ensure compliance with "rapid voltage change" requirements according to set out above. (Rapid Voltage Changes.)

Section sss. Protection and Fault Levels

Article 306. Protection and Fault Levels

(1). A VRPP operator shall design, implement, coordinate and maintain its protection system to ensure the desired speed, sensitivity and selectivity in clearing faults on VRPP's side of the connection point (POC).

(2). Protection functions required for protecting the TNO's network or the DC's network, as applicable, from getting out of normal operating ranges shall be specified by the TNO or the DC in consultation with the TNO, including trip-settings, response times for over-/under-voltage protection, and over-/under-frequency protection.

(3). A VRPP shall be equipped with effective detection of islanded operation in all system configurations and shall have the capability to shut down generation of power in such condition within 2 seconds.

(4). The islanded operation:

a. With part of the transmission network is not permitted unless specifically agreed with the TNO.

b. With part of the DC's network shall not be permitted unless specifically agreed with the TNO and DC.

(5). The coordination among protections at connection point must be agreed between TNO, the DC and the VRPP operator.

(6). The circuit breaker used for connection switching in transmission network connected generators or distribution network connected generators, as applicable, shall be equipped with a disconnection system to ensure safe operation during re-connection/re-synchronization to the grid.

(7). The TNO or DC, as applicable, may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the transmission network or the distribution network, as the case may be, except that, such a change shall not result in a VRPP being exposed to negative impacts from the transmission network or distribution network lying outside of the design requirements.

(8). The TNO or DC, where applicable, shall inform a VRPP operator of the highest and lowest short-circuit current that shall be expected at the POC as well as any other information about the transmission network or distribution network, as the case may be, as may be necessary to define the VRPP's protection functions.

(9). Where VRPP's protection equipment is required to communicate with the TNO's or DC's protection equipment, as applicable, it must meet the communications interface requirements specified by the TNO or DC, as applicable, and this Grid Code.

Section ttt. Information Exchange, Communication and Control

Article 307. Information Exchange, Communication and Control

(1). A VRPP shall be equipped to receive target values for control purposes from the TNO such as voltage/reactive power control as specified above in Article 295, active power curtailment as specified in Article 299 and other control functions as it may be applicable.

(2). A VRPP owner shall be responsible for data relating to MW forecast estimates and a VRPP availability estimates, at least a prediction intervals of 2 days-ahead, 1 day-ahead and 4 hours-ahead of real time. This data shall be made available to the TNO by a VRPP operator on a daily basis.

(3). All further requirements with regard to the exchange of information will be agreed on between a VRPP operator and the TNO or DC, as the case may be, within the bilateral connection agreement between the parties.

Article 308. Supervisory Control and Data Acquisition

(1). A VRPP shall provide Supervisory Control and Data Acquisition (SCADA) system with the capability to transmit data and receive instructions from the TNO to protect system reliability.

Article 309. Renewable Generating Facility Forecasting

(1). A VRPP shall install equipment necessary to automatically communicate to the TNO the expected and real-time renewable generation output and data for the purposes of generation forecast.

Section uuu. Testing, Inspection and Compliance Monitoring

Article 310. Testing, Inspection and Compliance Monitoring

(1). A VRPP shall demonstrate compliance with all applicable requirements specified in this Grid Code and any other applicable code developed by the Commission or technical standard approved by the TNO or DC, as applicable, before being allowed to connect to the TNO's network or DC's network, as the case may be, and operate commercially.

(2). A VRPP operator shall review and confirm to the TNO or DC, as applicable, compliance by a VRPP with every applicable requirement of this Grid Code.

(3). VRPP operator shall conduct tests or studies to demonstrate that the VRPP complies with each of the applicable requirements of this Grid Code and submit such tests to the TNO or DC, as applicable.

(4). The VRPP operator shall continuously monitor its compliance in all material respects with all the connection conditions of this Grid Code.

(5). Each VRPP operator shall submit to the TNO a detailed test procedure, emphasising system impact, for each relevant part of this Grid Code prior to every test and do so according to procedures indicated in this Grid Code.

(6). A VRPP operator shall also conduct tests on protection system and co-operate with the TNO regarding the same as specified in this Grid Code.

(7). The TNO or DC, as applicable, may issue an instruction requiring a VRPP to carry out a test to demonstrate that the VRPP complies with the code requirements and the VRPP shall not refuse such an instruction.

(8). A VRPP operator shall keep records relating to the compliance of the VRPP with each applicable section of this Grid Code, or any other code applicable to that VRPP, setting out such information that the TNO or DC, as applicable, reasonably requires for assessing power system performance, including actual VRPP performance during abnormal or continuous operating conditions.

(9). Records generated under this section of this Grid Code shall be kept for a minimum of 5 years, unless otherwise specified in this Grid Code, commencing from the date the information was generated.

EXEMPTION PROCEDURES, DISPUTE RESOLUTION AND IMPLEMENTATION

Chapter XVI. Exemption Procedures

Article 311. Cases of Exemption

1. Parties who are bound by this Grid Code have right to submit an application in order to be considered for exemption if the following conditions can be met:

   a) Prior to this Grid Code becoming effective they had an existing contract that would not otherwise be compliant with this Grid Code; or

   b) They consider this Grid Code will impose excessive and unreasonable costs upon them; and

   c) They can demonstrate that granting the proposed exemption furthers the purpose and guiding principles of this Grid Code.

2. In cases where exemption is granted based on (1) above, EWRC shall provide a timeline similar the transition provision in Article 324 to Article 326.

Article 312. Authority to Make Decision on Exemption

1. EWRC shall consider and make a written decision on exemptions stipulated in Article 311 of this Grid Code. In considering an application for exemption EWRC must consider:

   a) The rights granted to parties by contracts that were agreed prior to this Grid Code becoming effective;

   b) The views of the TNOs and SO on whether granting the exemption impacts their ability to achieve their performance targets;

   c) Whether the provision for which an exemption is sought imposes excessive and unreasonable costs upon the party applying for the exemption;

   d) Whether granting an exemption would impose costs on any other parties to this Grid Code;

   e) Whether granting the proposed exemption would further the guiding principles and purposes of the Grid Code as laid out in Article 4 and Article 5 respectively;

   f) The allocation of any costs associated with or arising from granting the exemption;

   g) The appropriate duration for any exemption; and

   h) Any conditions it considers should be imposed on any exemption.

2. For the avoidance of doubt EWRC may reject any exemption application which it reasonably considers is vexatious or trivial.

Article 313. File for Request of Exemption

A file for request of exemption shall comprise:

   a) Application for exemption;

   b) Valid copy of certificate of electricity activity licence (if possible);

c) Detailed explanatory report on technical specifications and obligations for exemptions and how exemptions meet requirements of Article 311.

Article 314. Acceptance of Application

1. Parties requesting for exemption shall submit copies of the application to EWRC.
2. Within 15 working days from the date of receipt of a file for request of exemption, EWRC shall be responsible to provide written notice to the party which submitted the file on the completeness of the file; if a file is incomplete, EWRC shall be responsible to specify what items are required to be supplemented.
3. Parties submitting a file must pay a fee for evaluation of the file for request of exemption in accordance with a reasonable fee to cover the costs of the EWRC as advised by the EWRC.

Article 315. Provision of Information by Related Parties

EWRC shall have the right to require TNOs, SO and related parties or parties likely to be impacted by the exemption to provide information and comments about exemption application.

Article 316. Withdrawal of Request of Exemption

1. A party wishing to withdraw its request of exemption after submission must provide written notice to EWRC.
2. EWRC shall not refund fees for evaluation of a file for request of exemption in the case stipulated in clause 1 of this article.

Article 317. Time-limits for Issuance of Decision

1. Within 30 working days from receipt of completed file for request of exemption, EWRC shall issue one of the following decisions:
   a) Agree to grant an exemption, with any relevant conditions; or
   b) Decline to grant an exemption, and the reasons for not granting.
2. Decision shall be sent to TNOs, SO and any impacted or related parties in requirement.
3. In complex cases, time-limit may be extended but not more than 20 working days; EWRC shall provide a written notice to the party which submitted the file, specifying the reason, at least three (3) working days prior to expiry of the time-limit for issuance of a decision.

Article 318. Revocation of Decision Granting Exemption

EWRC shall have the right to revoke granting exemption decision in the following cases:

a) Upon discovery of fraud during application for exemption;

b) When party granted exemption fails to fulfill the conditions and discharge the obligations to meet the due date promulgated in the decision granting exemption; or

c) When the conditions for exemption no longer exist.

Chapter XVII. Dispute Resolution and Breaches

Article 319. Principles for Dispute Resolution

1. Parties shall attempt to resolve disputes informally before bringing such disputes to EWRC.
2. Where parties bring dispute to EWRC, then EWRC will arrange a dispute resolution process as outlined below.
3. In arranging such dispute resolution EWRC must give due consideration to the purpose and guiding principles of this Grid Code as outlined in Article 4 and Article 5 respectively.
4. In process of dispute resolution, whenever a trace or signal of administrative or criminal violation is found, file of dispute shall be immediately transferred to the relevant legal authority.

Article 320. Informal resolution

If any dispute arises among the parties related to this Grid Code, the party alleging the dispute shall notify the other parties in writing of the dispute, and the parties shall attempt informally to settle such dispute between them in good faith within a period of sixty (60) days thereafter; provided that disputes about the payment of money shall be attempted to be settled informally within fifteen (15) days. After such sixty (60) day or fifteen (15) day, respectively, informal effort, the parties may seek EWRC assistance in resolution of the dispute, or seek any other remedy at law or equity.

Article 321. Dispute Resolution Panel

1. Within 15 working days from the day of receipt of request for dispute resolution EWRC shall convene a dispute resolution panel.
2. The dispute resolution panel shall consult EWRC concerning the dispute resolution process to be adopted.
3. Dispute resolution panel shall comprise of five (5) members, including a Commissioner of EWRC, with relevant experience, who shall be the Chairman and the other 4 shall have expertise in the following areas:
   a) 1 member in mediation and arbitration;
   b) 1 member with technical expertise in the development and operation of the power system;
   c) 1 member with commercial expertise in power system development and operation; and
   d) 1 member with legal expertise in relevant sections of Sierra Leone law and applicable decisions and codes.

4. Members of the dispute resolution panel must be independent of any party having a commercial interest.

Article 322. Dispute Resolution Procedures

1. After receipt of a request for dispute resolution, EWRC shall constitute a panel, as in Article 321, to commence the dispute resolution process.
2. Within 20 working days, the dispute resolution panel shall hold mediation with participants from related parties.
3. Within 30 working days of holding mediation talks with participants the dispute resolution panel shall make a recommendation on resolution to EWRC.
4. Within 10 working days of receiving such a recommendation EWRC shall issue a decision on resolving dispute. The decision is binding to parties.
5. If any party disagrees with the decision, that party may seek redress in any Court of Law in Sierra Leone.

Article 323. Dealing with Breaches of Grid Code

1. The Chairman of EWRC is authorized to issue decision dealing with breaches of this regulation.
2. Any party to this Grid Code may submit a complaint of breach to EWRC at any time.
3. Such an allegation of breach must include detailed explanatory report on:
   a) The party that is considered to be in breach;
   b) The aspect of this Grid Code that is considered to be in breach;
   c) The timing of the alleged breach;
   d) Any parties they consider to be impacted by the alleged breach;
   e) The impact of the alleged breach; and
   f) Any other issues they consider relevant.
4. EWRC shall have right to require related parties to provide information about the breach in requirement during process of investigation and dealing with breach.
5. Within 60 working days after notification, the Chairman of EWRC shall issue a decision dealing with a breach of this Grid Code. In case of no breach committed, EWRC shall inform parties in written notice with explanation.

Chapter XVIII. Implementation

Article 324. User Transition Provisions

1. Unless a user possesses a valid exemption, granted in accordance with the procedures of Chapter XVI, then where existing assets do not meet the technical standards of the Grid Code, users shall complete modification, upgrade or replacement of the assets within six (6) months from the day of effectiveness of this Grid Code.

Article 325. TNO Transition Provisions

1. Where a Transmission Network does not comply with the specific provisions of this Grid Code the relevant TNO will, within six (6) months of this Grid Code becoming effective, submit to EWRC for approval a plan to comply with said provisions, and any relevant exemptions it considers will be necessary during the transition period. Such a plan must take into account both the cost of bringing assets up to compliance with this Grid Code and the costs imposed on users of such assets not being compliant.
2. Within six (6) months of receipt of the proposed compliance plan of the TNO, the EWRC must advise the TNO, and other grid users, whether it:
   a) Accepts the proposed plan;
   b) Rejects the proposed plan; or
   c) Requires modification of the proposed plan.
3. As part of its consideration of the proposed compliance plan of the TNO, the EWRC will consult all users concerning the plan.
4. Where the EWRC accepts a TNO transition plan it shall include in its decision any related decisions on associated exemptions. For clarity it is noted that the EWRC may accept a plan without accepting all related exemption applications.

Article 326. SO Transition Provisions

1. Where the SO does not comply with the specific provisions of this Grid Code the SO will, within six (6) months of this Grid Code becoming effective, submit to EWRC for approval a plan to comply with said provisions, and any relevant exemptions it considers will be necessary during the transition period. Such a plan must take into account both the cost of bringing assets up to compliance with this Grid Code and the costs imposed on users of such assets not being compliant.
2. Within six (6) months of receipt of the proposed compliance plan of the SO, the EWRC must advise the SO, and other grid users, whether it:
   d) Accepts the proposed plan;
   e) Rejects the proposed plan; or

f) Requires modification of the proposed plan.

3. As part of its consideration of the proposed compliance plan of the SO, the EWRC will consult all users concerning the plan.
4. Where the EWRC accepts an SO transition plan it shall include in its decision any related decisions on associated exemptions. For clarity it is noted that the EWRC may accept a plan without accepting all related exemption applications.

Article 327. Implementing Guidelines

1. EWRC shall be responsible for providing guidelines and inspect the implementation of this regulation.
2. As part of preparing such guidelines the EWRC shall consult all grid users and affected parties on the draft guidelines and seek feedback on any issues users foresee in implementation of this regulation.

APPENDICES

Appendix 1. Generic Model Formulation

The formulation of the schedule and dispatch model is expected to consist of an objective function which maximizes the economic gains to the entire power system through a co-optimization of energy and applicable ancillary services (e.g., regulation reserve, spinning reserve, fast start reserves, cold start, and RMR) while subject to a set of constraint equations. Where the model cannot find a feasible solution, the constraint equations may be violated in accordance with the penalty value which signal the priority for violation set in the market rules so that the solver will be able to find a feasible solution and at the same time identify signal the stresses in the power system.

Set out below is a generic model formulation for the scheduling and dispatch model which co-optimize energy and reserves and includes a hydro energy constraint equation. It is noted that different versions of the model may be used for different purposes and time frames. For example, real time dispatch may not include the hydro energy constraint, but medium term security of supply assessment is likely to.

Objective function: To maximize economic gains to the entire power system

$$\left\{ \sum (D)_i (PD)_i - \sum (G)_i (PG)_i - \sum (R)_i (PR)_i - CVP \right\}$$

D_i : Demand quantity of customer, or power pool operator "***i***"
PD_i : Value of demand of customer or power pool operator "***i***" (fixed high value)
G_i : Energy quantity bid of generator or power pool operator "***i***"
PG_i : Price of energy bid of generator or power pool operator "***i***"
R_i : Reserve quantity bid of ancillary services provider "***i***" in a reserve zone (given by the SO)
PR_i : Price of reserve bid of ancillary services provider "***i***" in a reserve zone
CVP : Total cost of constraint violation

Subject to the following constraint equations[1]:

1. Generator or power pool operator energy resource constraint

$$G_{\min,ramp,i} \le G_i \le G_{\max,ramp,i}$$

the minimum and maximum generation of a generating unit, or power pool interconnection point (G_i) is dependent on its ability to ramp-down or ramp-up to its minimum and maximum generation

[1] The CVP parameter in each constraint equation is omitted.

2. Reserve resource constraint

$$R_{k,i} \leq \mathrm{R}_{\max,k,i}$$

the reserve schedule for resource "*i*" of reserve category "*k*" should be less than or equal to maximum reserve for category "*k*" of resource "*i*"

where:
k=1, Regulation reserve
k=2, Contingency reserve

3. Reserve and energy constraint

$$(R_{i,k=1} + R_{i,k=2}) + G_i \leq G_{\max,i}$$

the sum of reserve schedule for each reserve category "*k*" and plus the energy schedule (G_i), for each resource generator "*i*", must be less than or equal to the maximum stable generation *(G_{max})* of generator or power pool interconnection resource "*i*".

4. Bid limit constraint

Bid PG_i by a generator "i" has to be between the floor $PG_{floor,i}$ and the cap $PG_{cap,i}$ applicable to generator or power pool operator

$$PG_{floor,i} \leq PG_i \leq PG_{cap,i}$$

5. Nodal energy balance constraint

For each node "*n*", the total energy injection at node "*n*" must be equal to the energy withdrawal from node *"n"* inclusive transmission losses

$$\sum G_{i,n} + \sum line\_flow\_in = \sum D_{i,n} + \sum line\_flow\_out + losses$$

6. Area reserve requirement constraint

$$\sum_i \sum_j R_{i,j,k} + Q_{R_{k,a}} = R^{req}{}_{k,a}$$

Area "*a*" Reserve Requirement Constraint for each reserve type "*k*" - the Reserve requirement (R^{req}) for each area shall be satisfied by local generators or dispatchable loads on each specified area "*a.*"

Where:

$Q_{R_{a,k}}$ *refers to the MW amount by which each reserve type "k" was violated in area "a."*

$R_{i,j,k}$ *refers to the MW quantity of the jth reserve offer block of the ith resource.*

7. Line flow constraint

$$P_{i,j} \leq P_{l,limit}$$

Line flow constraint for any line "*l*" where:

$P_{i,j}$ = MW power flow from node "*i*" to "*j*."

$P_{l,limit}$ = MW limit of line "*l*" connecting node "*i*" to "*j*."

8. Regulation headroom constraint

$$G_i - R_{i,k=1} \geq G_{min,i}$$

The head-room constraint is imposed on REG reserve resources in order to schedule the energy output of the generator or power pool interconnection resource "*i*" with consideration of its minimum stable generation limit

9. Hydro energy constraint

Hydro power plant is permitted to bid the maximum water volume

$$\sum_{t=1}^{T} G_t \leq G_{day}$$

Where G_{day} is the maximum generation output based on the maximum water volume for the day

10 Imports and exports

Power pool imports and exports are included in the scheduling and dispatch process as generation offers and demand bids at the interconnection point as incorporated above.

11. Other security constraints

$$f(G,R,P)=c$$

Where G is generation output, R is reserve, P is line flow.

12. Constraint violation coefficient

During the optimization process, the solver may not be able to find a feasible solution. To enable the solver find a solution, some constraint(s) will need to be violated. The constraint violation penalty regime sets out the priority for the constraints to be violated. Generally, the constraints that have least impacts on the security of the system (e.g., contingency requirements) are allowed to be violated before other constraints (e.g., generation resource constraints).

Constraint type	Violation priority
Regulation	1
Contingency reserve	2
Over generation	3
Under generation	4
Hydro energy constraint	5
Transmission line	6
Other security constraint	7

Appendix 2. Market Timetable

Performance Timetable

ID	Time	Content	Sender	Receiver	Means
1	Before 0830hrs and 2030hrs on Day D-1	Forecast demands from all DCs, DCCs and power pool operators for the day D	All DCs, DCCs and power pool operators	SO	On the SO Website
2	Before 0900hrs and 2100hrs on Day D-1	Forecast the system demand for the day D based on the purchasing demand of all DCs, DCCs and power pool operators	SO	Market Participants	On the SO Website
3	As per Market Rules	Bidding for the day D;	Market Participants	MO	On the SO Website
4	By 1000hrs	Provide all offers to SO	MO	SO	As advised by SO
5	Before 1500hrs Day D-1	Publishing the expected day D schedule,	SO	Market Participants	On the SO Website

Appendix 3. Connection Registration Information

(Apply for new connection point or modification at existing connection point)
Name of User:
Address:
Contact person:
Phone:
Fax:
Email:

Part 1
General Information

1. Project description:

- Name of project
- Scope of Activities/Production type
- Expectation output/Production capacity
- Projected beginning date of construction
- Projected operation date
- Current connection point
- Proposed connection point
- Proposed voltage level and number of connecting circuits
- Proposed transmission network connection date

2. Map and schemes:

- Provide a 1:50000 topographic map, with the location of User's Project marked with an "X", connection point and related part of transmission network.
- Provide a plan of the site (1:200 or 1:500) indicating the proposed location for transmission station compound, generation units, transformers, site buildings, connection point.

3. Legal documentation

- Legal documentation (copy of investment Licence, decision of establishment, business registration, other legal Licences).

Part 2
Demand Data

(Apply to Demand Users)

1. Power and energy requirements

Active power: MW
Reactive power: MVAr
Energy per day/month/year: kWh

2. Measured and forecast demand data

2.1 Measured demand data: The existing User is required to provide:

- Daily load curves of all days in the latest year with clear specification of:
  - Active and reactive power received from TNO network;
  - Active and reactive power self - produced (if existing).
  - Monthly energy consumption and production of the latest years.

2.2 5 years forecast of demand

- The existing Demand User is required to provide daily load curve forecast in peak day and peak-off day of every month for each of the 5 succeeding years. The new Demand User is required to provide such a forecast for the 5 succeeding years from the official date of operation.
  In this forecast, the powers (in MW and MVAr) received from TNO's transmission network and self - produced must be specified.
- Monthly energy consumption for 5 next years with clear specification of which received from relevant TNO's transmission network and which self - produced.

2.3 The document, which forecast is based on (if existing)

3. Technical data of Demand User's Grid

3.1 Electrical schematics:

- System layout
- Single line diagram, which includes:
  - Busbar arrangements
  - Electrical circuits (overhead line, underground cable, transformers);
  - Phase arrangements;
  - Earthing arrangements;
  - Switching facilities;
  - Operating voltages;
  - Protection configurations;

- Transmission network connection point;
- Arrangements of reactive compensation equipment.

These schematics is required for connection site only. Any intended modification or/and future extension must be clearly specified.

3.2 Electrical equipment

Switching equipment (breaker, disconnector) of all power circuits related to connection point

- Rated and Operating voltage (kV).
- Rated current (A)
- Rated 3-phase short circuit breaking current (kA)
- Rated 1-phase short circuit breaking current (kA).
- Rated 3-phase load breaking current (kA)
- Rated 1-phase load breaking current (kA)
- Rated peak 3-phase short circuit making current (kA)
- Rated peak 1-phase short circuit making current (kA)
- Basic insulating level - BIL (kV)

Transformers

- Rated voltage and winding arrangement
- Rated MVA of each winding.
- Tapped winding, tap changer type (on load or off load), tap change range (number of tap and tap changer step size).
- Tap change cycle time
- Earthing arrangement (neutral earthing resistance and reactance)
- Saturation curve
- Positive sequence resistance and reactance of transformer at nominal, minimum and maximum tap ($R + jX$ in % on rating MVA of transformer). For three windings transformer, where there are external connections to all three windings, the resistance and reactance between each pair of windings is required, measured with the third set of terminals open - circuit..
- Zero-sequence resistance and reactance of transformer at nominal, minimum and maximum tap (Ω)
- Basic insulation level (kV)

Reactive compensation equipment (capacitors/shunts)

- Type of equipment (fixed or variable), capacitive and/or inductive rating or its operating range in MVAr.
- Resistance / reactance, recharging/discharging current
- For controlled capacitor/shunt, please provide details of control logic, controlled data such as voltage, load, switched or automatic, operating time and other setting.

Voltage Transformer (VT)/ Current Transformer (TI)

- Rated Ratio
- Testing Certificates in accordance with Measuring Code

Protection and Control system

- Protection configurations
- Proposed setting values
- Fault clearing time of main and backup protection
- Auto - re-closer cycles (if available)
- Control management and data communication

Transmission lines and cables related to power connection point

- Resistance / reactance / capacitor
- Rated and maximum loading current

3.3 Short circuit data

- Three-phase short circuit current (in-feed at the instant of fault and after sub-transient fault current contribution has substantially decayed) from User's system at connection point
- Zero sequence resistance and reactance values of User's system seen from the connection point.
- Voltage value before the fault consistent with the maximum fault current.
- Negative sequence resistance and reactance values of User's system seen from the connection point.
- Zero sequence resistance and reactance values of the Pi equivalent scheme of User's system (if existing).

3.4 Reserve requirement

Demand User supplied from two or more power resource, must clearly specify

- Type of reserve power resource
- Reserve capacity requirement (in MW and MVAr)

4. Load characteristics

Characteristic Unit
Power factor
Voltage sensitivity MW/kV, MVAr/kV
Frequency sensitivity MW/Hz, MVAr/Hz
Maximum and average phase unbalance %
Maximum harmonic content
Long-term and short-term flicker severity
Load fluctuation

Demand User with capacity requirement from 5 MW up at connection point is required to provide following data:

- Change rate of load (kW/s and kVAr/s) both increasing and decreasing.
- The shortest repetitive time interval between load fluctuations (in seconds);
- The magnitude of the largest step changes in power demand (kW, kVAr).

5. Other requirements for power quality

Part 3
Power Plant Data
(Apply for Power Generator)

1. Plant description

- Name of power plant
- Location
- Type of plant (hydropower, coal-fired power, gas-fired power…)
- Number of generator and rated capacity
- Estimated energy generation (MWh / month or year)
- Proposed export capacity (MW)
- Proposed commercial operation time
- Proposed voltage level of connection point (kV)

2. Electrical schematics

- System layout
- Single line diagram, which includes:
  - Busbar arrangement;
  - Electrical circuits (power transmission line, cable, transformers);
  - Phase arrangements;
  - Earthing arrangements;
  - Switching facilities;
  - Operating voltages;
  - Protective configurations;
  - Transmission network connection point;
  - Arrangements of reactive compensation equipment.

These schematics is required for connection site only. Any intended modification or/and future extension must be clearly specified.

3. Generator Operating Characteristics:

For each individual Unit, fill in the followings:
Unit number:
Rated capacity MW
Generator Rating MVA
Generating station auxiliary load MW
Generating station auxiliary load MVAr
Terminal Voltage kV
Active Power range MW-MW
Reactive power generated at rated active power MVAr
Reactive power received at rated active power MVAr
Short-circuit ratio
Rated stator current A

Rated rotor current at rated output (rated active power, rated power factor, rated terminal voltage) and rated speed of rotor A
Rated rotor voltage kV

- Operation range of generation unit including thermal and exciter limits
- Open circuit magnetization curve
- Short-circuit characteristic
- Zero-power factor curve
- Voltage curve
- Time to synchronize from warm (h)
- Time to synchronize from cold (h)
- Minimum operation time
- Minimum stop time
- Normal loading rate, MW/min
- Normal de-loading rate, MW/min
- Type of start-up fuel
- Ability to changing fuels on load
- Available modes
- Time to change modes on load
- Control range for secondary frequency regulation system (SFRS) operation (MW)
- Other relevant operating characteristics
- Give details of reserve capability of the generator in different operating modes.

For thermal power plant, please provide a functional block diagram of the main plant components, showing boilers, alternators, and any heat or steam supplies.

4. Technical specification of each generation unit [per unit]

Parameters	Symbol and value
Direct axis synchronous reactance	X_d
Direct axis transient reactance	X'_d
Direct axis sub-transient reactance unsaturated	X''_d
Quadrature axis synchronous reactance	X_q
Quadrature axis transient reactance unsaturated	X'_q
Quadrature axis sub-transient reactance	X''_q
Negative sequence reactance	X_2
Zero sequence reactance	X_0
Stator resistance	R_a
Stator leakage reactance	X_L
Poiter reactance	X_p

Generator time constants	Symbol and value
Direct axis open circuit transient	Tdo’ (s)
Direct axis open circuit sub-transient	Tdo’’ (s)
Quadrature axis open circuit transient	Tqo’ (s)
Quadrature axis open circuit sub-transient	Tqo’’ (s)
Direct axis short-circuit transient	Td’ (s)
Direct axis short-circuit sub-transient	Td’’ (s)
Quadrature axis short-circuit transient	Tq’ (s)
Quadrature axis short-circuit sub-transient	Tq’’ (s)

- Turbine generator inertia constant for entire rotating mass (MWsec/MVA)*

5. Excitation system

Please provide data relating to excitation system and power stabilizer system (PSS) in Laplace – domain control block diagram in accordance with IEEE standard excitation models (or as otherwise agreed with TNO) completely specifying all time constants and gains.

6. Speed Governor system and stabilizer system

Please provide Laplace – domain control block diagram in accordance with IEEE standard (or as otherwise agreed with relevant TNO) completely specifying all time constants and gains.

7. Control and protection system

Please provide detailed information for control and protection system of generator.

8. Black start (if available)

Provide information about black start system.

9. Environmental impact

Please provide all information relating with gas emission (for thermal PP):

Parameter Value

CO2 gas
Tonnes CO2/tonnes fuel
CO2 removal efficiency

SO2 gas
Tonnes SO2/tonnes fuel
SO2 removal efficiency

NOx gas tonnes NOx/exported MWh curve

10. Pumped-storage power plant

Please provide following data:

- Reservoir capacity (MWh pumping)
- Maximum pumping capacity (MW)
- Minimum pumping capacity (MW)
- Maximum generating capacity (MW)
- Minimal generating capacity (MW)
- Efficiency (generating/pumping ratio %)

11. Wind turbine generation station

Please provide following data:

- Type of turbine (fixed or variable speed);
- Manufacturer details on technical specifications and operating characteristics with particular reference to flicker and harmonic performance;
- Seasonal operation regimes of generation: seasonal or continuous;
- List the anticipated maximum export level in TNO's transmission network for each calendar month (MW);
- Typical daily generation curve of the month of maximum export;
- Details of expected rapid or frequent variations in output, including magnitude, maximum change rate, frequency and duration.

12. Forecast availability

- Expected maintenance requirement: weeks/year
- Availability (apart from the expected scheduled maintenance requirements)

Availability Reason Available Exported MW Time %
Full availability
Partial availability
Forced outage probability
Total 100%

- Energy Limitations
- Daily generation (GWh)
- Weekly generation (GWh)
- Monthly generation (GWh)
- Yearly generation (GWh)

Hydropower plant is required to provide expected generation (GWh) of each month in the year, reservoir regulation documentation.

13. Technical data for electrical equipment in connection points

Switching equipment: breakers, disconnector of all circuit connection related with connection point.

- Rated and Operating voltage (kV).
- Rated current (A)
- Rated 3-phase short circuit breaking current (kA)
- Rated 1-phase short circuit breaking current (kA).
- Rated 3-phase load breaking current (kA)
- Rated 1-phase load breaking current (kA)
- Rated peak 3-phase short circuit making current (kA)
- Rated peak 1-phase short circuit making current (kA)
- Basic insulating level - BIL (kV)

Transformers

- Rated voltage and winding arrangement
- Rated MVA of each winding.
- Tapped winding, tap changer type (on load or off load), tap change range (number of tap and tap changer step size).
- Tap change cycle time
- Earthing arrangement (neutral earthing resistance and reactance)
- Saturation curve
- Positive sequence resistance and reactance of transformer at nominal, minimum and maximum tap ($R + jX$ in % on rating MVA of transformer). For three windings transformer, where there are external connections to all three windings, the resistance and reactance between each pair of windings is required, measured with the third set of terminals open - circuit.
- Zero-sequence resistance and reactance of transformer at nominal, minimum and maximum tap (Ω)
- Basic insulation level (kV)

Reactive compensation equipment (capacitors/shunts)

- Type of equipment (fixed or variable), capacitive and/or inductive rating or its operating range in MVAr.
- Resistance / reactance, recharging/discharging current
- For controlled capacitor/shunt, please provide details of control logic, controlled data such as voltage, load, switched or automatic, operating time and other setting.

Voltage Transformer (VT)/ Current Transformer (TI)

- Rated Ratio

- Testing Certificates in accordance with Measuring Code

Protection and Control system

- Protection configurations
- Proposed setting values
- Fault clearing time of main and backup protection
- Auto - recloser cycles (if available)
- Control management and data communication

Transmission lines and cables related to power connection point

- Resistance / reactance / capacitor
- Rated and maximum loading current

14. Generator's own consumer

The Generator owns the consumer shall provide following load forecasted data:

- Maximum and minimum demand forecast.
- Power energy requirement
- Load characteristic (see Part 2)

Appendix 4. Connection Agreement

CONNECTION AGREEMENT
BETWEEN
TNO (Name of TNO)
AND
.....*(Name of User)*.....

Location, Day/Month/Year
Based on:
• Connection Application submitted to TNO date .....month .... year by (*User*)
• Additional documentation from (*User*) in date .....month .... year
• Memorandum/Memoranda of understanding between both sides dated ....
Today, (*day, month, year*) ..... in ..... (*location of signed ceremony*)
TNO (abbreviated TNO),

Address:
Telephone:
Fax:
Bank account number:
Represented by Mr. / Ms. ..... Title: .....

and
(*Name of the User, legal status*) hereinafter called the User
Address:
Telephone:
Fax:
Bank account number:
Represented by Mr. / Ms. ..... Position .....
has agreed to sign this Connection Agreement with following articles:

Article 1: TNO accepts the User to TNO's network at voltage level .....
Attached Attachment 1 is a single line diagram at connection site.

Article 2: Fixed Asset Boundary Document is described in Attached Attachment 2 .

Article 3: The User has responsibility to develop its own network in accordance with technical specifications submitted in Attachment 3, complying with Grid Code and other Rules approved by competence organizations.

Article 4: TNO has responsibility to develop its own network to connect to the User.

Article 5: Expected connection day is..... (date, month, year).

Article 6: The User commits to operate its power network/plant in accordance with the Grid Code for Transmission Network and other Rules approved by TNO and competence organizations.

Article 7: After connection, the User has the right to propose temporary or long-term disconnection to TNO only in cases described in attached Attachment 4, complying to the Grid Code.

Article 10: During operation, any change(s) or modification(s) related to connection point and connection equipment shall be agreed by both sides in official letter(s) attached to this Connection Agreement.

Article 11: This Connection Agreement shall be effective from signing date.

Article 12: This Connection Agreement shall have 4 copies, each side keeps 2 copies.

User Representative
(*Name, Title*)

TNO Representative
(*Name, Title*)

Attachment 1
Single line diagram at CONNECTION site

Attachment 2

FIXED ASSET BOUNDARY DOCUMENT

(Attached to Connection Agreement No .....)

Date ..... Month ..... Year .....

Name of substation:

Location:

Address:

Telephone:

TNO transmission network operator:

User Operator..... (*Name of User*):

Connection point:

Assets boundary:

Head/Director of Substation
(*Signed and name*)

TNO transmission network operator
(Signed and name)

User Grid Operator.....*(name)*
(Signed and name)

LIST OF FIXED ASSETS
AT CONNECTION POINT

I. Main equipment (including transmission lines)

Number and Name of equipment
Main technical specifications
Investor/owner
Remark

II. Secondary equipment

Number and Name of equipment
Main technical specifications
Investor/owner
Remark

III. Measuring system

Number and Name of equipment
Main technical specifications
Investor/owner
Remark

IV. Other equipment

Number and Name of equipment
Main technical parameter
Investor/owner
Remark

Attachment 3

TECHNICAL SPECIFICATIONS OF THE USER

(Including all updated and revised data described in part 2 and part 3 of Transmission Network Connection Application, which has been updated and/or revised)

Attachment 4
TEMPORARY / LONG -TERM DISCONNECTION FROM USER REQUIRMENT

(Description all cases The User can propose temporary (less than 12 months) and long-term disconnection to TNO and relevant responsibility of the User for each cases)

Appendix 5. Transmission Network Standing Data

Each TNO shall provide to the SO the following technical data on all its Transmission Network Assets:

Technical data of TNO's Assets

1 Electrical schematics:

- System layout
- Single line diagram, which includes:
  - Busbar arrangements
  - Electrical circuits (overhead line, underground cable, transformers);
  - Phase arrangements;
  - Earthing arrangements;
  - Switching facilities;
  - Operating voltages;
  - Protection configurations;
  - Transmission network connection point;
  - Arrangements of reactive compensation equipment.

These schematics are required for connection site only. Any intended modification or/and future extension must be clearly specified.

2 Electrical equipment

Switching equipment (breaker, disconnector) of all power circuits related to connection point

- Rated and Operating voltage (kV).
- Rated current (A)
- Rated 3-phase short circuit breaking current (kA)
- Rated 1-phase short circuit breaking current (kA).
- Rated 3-phase load breaking current (kA)
- Rated 1-phase load breaking current (kA)
- Rated peak 3-phase short circuit making current (kA)
- Rated peak 1-phase short circuit making current (kA)
- Basic insulating level - BIL (kV)

Transformers

- Rated voltage and winding arrangement
- Rated MVA of each winding.
- Tapped winding, tap changer type (on load or off load), tap change range (number of tap and tap changer step size).
- Tap change cycle time
- Earthing arrangement (neutral earthing resistance and reactance)

- Saturation curve
- Positive sequence resistance and reactance of transformer at nominal, minimum and maximum tap ($R + jX$ in % on rating MVA of transformer). For three windings transformer, where there are external connections to all three windings, the resistance and reactance between each pair of windings is required, measured with the third set of terminals open - circuit.
- Zero-sequence resistance and reactance of transformer at nominal, minimum and maximum tap (Ω)
- Basic insulation level (kV)

Reactive compensation equipment (capacitors/shunts)

- Type of equipment (fixed or variable), capacitive and/or inductive rating or its operating range in MVAr.
- Resistance / reactance, recharging/discharging current
- For controlled capacitor/shunt, please provide details of control logic, controlled data such as voltage, load, switched or automatic, operating time and other setting.

Voltage Transformer (VT)/ Current Transformer (TI)

- Rated Ratio
- Testing Certificates in accordance with Measuring Code

Protection and Control system

- Protection configurations
- Proposed setting values
- Fault clearing time of main and backup protection
- Auto - recloser cycles (if available)
- Control management and data communication

Transmission lines and cables related to power connection point

- Resistance / reactance / capacitor
- Rated and maximum loading current

3 Short circuit data

- List of assumed system conditions for calculation of system short circuit data
- Three phase short circuit current (infeed at the instant of fault and after sub-transient fault current contribution has substantially decayed) from TNO's system at connection point
- Zero sequence resistance and reactance values of TNO's system seen from the connection point.
- Voltage value before the fault consistent with the maximum fault current.

- Negative sequence resistance and reactance values of TNO's system seen from the connection point.
- Zero sequence resistance and reactance values of the Pi equivalent scheme of TNO's system (if existing).

Appendix 6. Distribution Service Customer Application Form

Note: Where indicated, shaded areas are form completion by the service provider. Please provide any additions details in the areas designated for notes.

Customer Contact Person 1 Title:	Customer Contact Person 1 details
Customer's preferred form of address	Full Name:
	Job Title:

Customer Contact Person 2 Title:	Customer Contact Person 2 details
Customer's preferred form of address	Full Name:
	Job Title:

Company Name:

As per registration with the Corporate Affairs Commission (CAC)

Corporate Affairs Commission (CAC) Registration Number:

As issued by the Corporate Affairs Commission (CAC)

Customer Contact Person 1 Telephone:	Customer Contact Person 1 Mobile:
Customer's contact number incl. dialing code and telephone number	*Customer's contact number incl. dialing code and telephone number*
Customer Contact Person 1 Fax:	Customer Contact Person 1 email:
Customer's contact number incl. dialing code and fax / telephone number	*Customer's contact email address*
Customer Contact Person 2 Telephone:	Customer Contact Person 2 Mobile:
Customer's contact number incl. dialing code and telephone number	*Customer's contact number incl. dialing code and telephone number*
Customer Contact Person 2 Fax:	Customer Contact Person 2 email:
Customer's contact number incl. dialing code and fax / telephone number	*Customer's contact email address*

Customer's physical address:

Customer's personal physical location

Customer's postal address:

Customer's preferred postal contact address

Physical connection to the Transmission or Distribution Network required? (Y / N)

If not, indicate nature of business (eg. Directly Connected Customer, Trader, etc.):

Type of quotation required (*please tick*):	Feasibility:	Firm:

Notes:

Additional customer information

The following field are to be completed by the Service Provider:		
Customer ID:	Customer Type:	Existing customer:
Unique customer number	*Indicate whether individual / company / partnership / other*	*Existing customer (Y/N)*
	Credit Indicator:	
Indicates if customer is subsidiary to existing customer	*Indicate if customer has outstanding balance(s)*	

Application Date:	Connection Voltage (kV): / MVA:
Customer's initial application date YYYY/MM//DD	*Indicate connection voltage* / *Requested connection capacity*
Requested Completion Date:	Estimated Monthly Consumption / Generation (MWh):
When customer wants supply available YYYY/MM//DD	*Customer's projected usage / generation for this point of supply (POS)*
Temporary Connection:	Owner or Tenant:
If short-term, period (months) for which connection is required	*Customer's owns / rents property for this application*

POS / Physical connection address:	
Longitude:	Latitude:

Full description of the property / title deed where supply is required: Street address, No., etc. Not a postal address

Usage Category (*Please tick*)

Industrial:	Commercial:	Distribution:	
Generation:	International:		
Other (*Please specify*):			

Nearest Existing Distribution Connection:

Distribution substation closest to POS

Other Distribution Network Connection:

Does customer have other distribution connections / points of supply?

Standard or Enhanced Reliability or Premium Connection:

Is the customer connection a Standard connection or an Enhanced Reliability connection or a Premium connection?

Special Instructions:

Customer's additional information regarding application

Cancel Date and Reason:

Details of why application is no longer required *YYYY/MM/DD*

Note that further information may be required before a quotation can be provided

The following field are to be completed by the Service Provider:

Application ID	POS ID
Unique number for current customer	*Unique number applicable to point-of-supply*

Application Type ID	NEW	INCR	DECR	CHNG	LINES
Note: Only one (1) application type ID per supply application	New POS / Connection	Increase of Connection to:	Decrease of Connection to:	Change of Customer	Existing lines to be moved
	MVA	MVA	MVA	MVA	MVA
	Size of supply required	*Size of supply required*	*Size of supply required*	*Current supply*	*Size of supply required*

Request Priority Indicator	Request Priority Reason
High / Medium / Low	*Reason for assigning request as High / Medium / Low*

Customer Core Business:	File No:	Project ID:
	For special file reference only	

Grid Region:	No of Stands
	No. of stands at POS address

Application Remarks:
Additional Information regarding application

Ref. No(s):
Details of any other transmission POS's linked to the customer

Quotation Date:	Agreement Date:
Date on which application completed *YYYY/MM/DD*	*Date agreement completed* *YYYY/MM/DD*
Connection Fee Amount:	Connection Fee Receipt No.:
	Unique no.
Date of receipt of customer's payment *YYYY/MM/DD*	

Appendix 7. Embedded Generator Connection Application Form

Note: This form to be completed in full and returned to the Distributor together with requested information for review and concurrence

1	Date:
2	Applicant Particulars Name of Applicant: Address: Telephone: Fax: Email
3	Project Details Project Name Project Location: Project Contact Name & Telephone Number: Facsimile: Project Type: (co-generation, combined cycle, hydraulic, etc.)
4	Construction Schedule Projected Start-up of Construction: Construction Power Requirements: Projected In-Service Date of Embedded Generator:
5	Site plan Site plan to show scaled mapping of existing lot lines, road crossing, etc.
6	Preliminary design Design to show generators, transformer, proposed connection point, isolating devices, protection schemes, etc.
7	Generator specifications Manufacturer: Fuel type: Rated MVA: Rated MW: Rated Voltage: Rated Power Factor: Inertial Constant: Maximum MVAR Limit: Neutral to Earth Resistance in Ohms: Xd – Synchronous reactance in p.u: X'd - Direct Axis transient reactance in p.u: X"d – Direct axis sub-transient reactance in p.u: X2 – Negative sequence reactance in p.u:

	X0 – Zero sequence reactance in p.u
8	Generator and unit transformer specifications Voltage and power ratings: Windings configuration: Neutral earth resistors or reactors: Positive and zero sequence impedances in p.u: R1: X1: RO: XO:
9	Expected Consumption (details to be clarified with the relevant Distributor)
10	Future Site Developments plans
11	Proposed Plant Design Operating characteristics :
12	Any other additional information :

I request the Distributor to proceed with a preliminary review of this Embedded Generation interconnection application and I agree to pay the cost associated with completing this review. I further consent to the Distributor providing this information to the National Transmission Company and other Distributors as required.

Name: _____ Signature: _____

Title: _____ Date: _____

Appendix 8. Information confidentiality

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 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 expense return to the Information Owner all hard copy material and electronic media 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 his 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 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 his 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/she becomes aware of the leak, and shall provide 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 ……

Appendix 9. Customer data – Planning and Connection Process

LV – Low Voltage, MV – Medium Voltage, HV – High Voltage

Information and data to be provided by Customers	**LV Customers**	**MV/HV Customers**
Demand and Network Data		
Connected load		
Maximum demand		
Type of load		
Maximum load on each phase		
Connection date		
Fluctuating loads		
Disturbing loads		
Electrical Diagrams and Connection Point Drawings		
Generation and transformation equipment		
Electrical circuits including overhead lines and underground cables		
Substation bus arrangement		
Grounding arrangement		
Phasing arrangement		
Switching facilities		
Circuit parameters from the Customer's substation to the Connection Point in the Distribution System		
Rated and operating voltage		
Positive sequence impedance		
Positive sequence susceptance		
Zero sequence impedance		
Zero sequence susceptance		
Power transformer data		
Rated MVA		
Rated voltage		
Winding arrangement		
Positive sequence impedance @max, min and nominal tap		
Zero sequence reactance		
Tap changer information		
Basic insulation level		
Switchgear information including circuit breakers, load break switches and disconnect switches at the connection point		
Reactive power compensation plant		
Rated capacity in MVAR		
Rated voltage		

Type of reactive power compensation plant		
Operation and controls		
Demand transfer capabilities in case the portion of the customer load is or can be supplied from another connection point		

Appendix 10. Embedded generator data – Planning and Connection Process

LV – Low Voltage, MV – Medium Voltage, HV – High Voltage

Information and data to be provided by Customers	**LV Customers**	**MV/HV Customers**
Demand and Network Data		
Connected load		
Maximum demand		
Type of load		
Maximum load on each phase		
Connection date		
Fluctuating loads		
Disturbing loads		
Electrical Diagrams and Connection Point Drawings		
Generation and transformation equipment		
Electrical circuits including overhead lines and underground cables		
Substation bus arrangement		
Grounding arrangement		
Phasing arrangement		
Switching facilities		
Circuit parameters from the Customer's substation to the Connection Point in the Distribution System		
Rated and operating voltage		
Positive sequence impedance		
Positive sequence susceptance		
Zero sequence impedance		
Zero sequence susceptance		
Power transformer data		
Rated MVA		
Rated voltage		
Winding arrangement		
Positive sequence impedance @max, min and nominal tap		
Zero sequence reactance		
Tap changer information		
Basic insulation level		
Switchgear information including circuit breakers, load break switches and disconnect switches at the connection point		
Reactive power compensation plant		
Rated capacity in MVAR		
Rated voltage		

Type of reactive power compensation plant		
Operation and controls		
Demand transfer capabilities in case the portion of the customer load is from another connection point		